UNIVERSITY OF ALBERTA LIBRARY
0 1620 0303 8021

Ex libris
UNIVERSITATIS
ALBERTÆNSIS

QUAECUMQUE VERA

Digitized by the Internet Archive
in 2014

https://archive.org/details/boarddeci1991_94

ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1991-94

ISSUES NOT PRINTED D 91-4
D 92-2
D 93-2

UNIVERSITY LIBRARY
UNIVERSITY OF ALBERTA

ALBERTA. ENERGY RESOURCES CONSERVATION BOARD. DECISIONS

NUMBER	APPLICATION NUMBER	TITLE
D 91-1	910018	Polaris petroleums ltd. APPLICATION FOR A WELL LICENCE PROVOST FIELD
D 91-2	901631 901632	APPLICATIONS BY SHELL CANADA LIMITED FOR PERMITS TO CONSTRUCT PIPELINES TO TRANSPORT SOUR GAS AND FUEL GAS IN THE WATERTON AREA
D 91-3	910227	POINTER EXPLORATION CORP. APPLICATION FOR A WELL LICENCE BAN TRY FIELD
D 91-5	910459	MANALTA COAL TLD. TO MODIFY THE BASE PLAN COAL MINING SCHELULE OF VESTA MINE
Memorandum	910253	APPLICATION FOR A WELL LICENCE OKOTOKS FIELD CANADIAN OCCIDENTAL PETROLEUM LTD.
MEMORANDUM	910336	APPLICATION BY EDMONTON POWER FOR THE COMMISSIONING SCHEDULE OF GENESEE UNIT NO. 1
D 91-6	910114 910115 910116 910505	APPLICATIONS BY THE IMPERIAL PIPELINE COMPANY, LIMITED/ ESSO RESOURCES (1989) LIMITED TO CHANGE SUBSTANCE IN THE EDMONTON TO SUNDRE PIPELINE FROM BLENDED BITUMEN TO NATURAL GAS AND FOR ASSOCIATED PIPELIN FACILITIES AND CONNECTIONS
	910357	APPLICATION BY NORTHWEST UTILITIES LIMITED TO RECONSIDER APPROVAL OF FEDERATED PIPELINES LIMITED NATURAL GAS LIQUIDS PIPELINE
D 91-7	910285	APPLICATION BY MID-WEST GAS TRANSMISSION LTD. TO CONSTRUCT A RAW GAS PIPELINE GOLDEN SPIKE AREA
D 91-8	901851 901852 901853 910048 910049	HOME OIL COMPANY LIMITED AND SCURRY-RAINBOW OIL LIMITED HAMBURG AREA COMMONPROCESSOR RATEABLE TAKE SPECIAL TWO-SECTION GAS DRILLING SPACING UNIT SWEET NATURAL GAS PIPELINE FUEL GAS PIPELINE
D 91-9	910284 910314 910597	STRATHFIELD OIL & GAS LTD APPLICATIONS FOR A-PERMIT TO CONSTRUCT A PIPELINE -APPROVAL TO CONSTRUCT A SATELLITE PRODUCTION FACILITY -A WELL LICENCE PROVOST FIELD

D 91-10	910777	NORCEN ENERGY RESOURCES LIMITED APPLICATION FOR A WELL LICENCE PROVOST FIELD
D 91-11	901415	TRANSALTA UTILITIES CORPORATION 138-kV TRANSMISSION LINE 848L BANALTO-CAROLINE AREA
D 91-12	910336	THE CITY OF EDMONTON (EDMONTON POWER) GENESEE POWER PLANT
D 91-13	910665	APPLICATION BY POLARIS PETROLEUMS LTD. FOR RESCISSION OF BOARD APPROVAL NO. 2534 JOSEPH LAKE AREA - JOARCAM VILING POOL
D 91-14	901415	TRANSALTA UTILITIES CORPORATION 138kV TRANSMISSION LINE 848L BANALTO-CAROLINE AREA
D 91-15	911262	APPLICATION BY BOW RIVER PIPE LINES LTD. FOR A PERMIT TO CONSTRUCT A CRUDE OIL PIPELINE AND PUMPING FACILITIES SOUTHTERN ALBERTA
Memorandum	910253 911089	APPLICATION FRO WELL LICENCES OKOTOKS FIELD CANADIAN OCCIDENTAL PETROLEUM LTD.
D 92-1	910454	SIGNALTA RESOURCES LIMITED COMMONCARRIER SUGDEN GRAND RAPIDS H AND COLONY UNDEFINED POOLS
D 92-3	920128	APPLICATION BY FEDERATED PIPE LINES LTD. FOR A PERMIT TO CONSTRUCT A HIGH VAPOUR PRESSURE PRODUCTS PIPELINE AND METERING FACILITIES SCHESON TO FOR SASKATCHEWAN
D 92-4	920563 920623	APPLICATIONS BY KOCH PIPELINES LIMITED FOR A PERMIT TO CONSTRUCT A CONDENSATE PIPELINE AND A PUMP STATION IN THE COCHRANE-MADDEN AREA
D 93-1	921279 921526-7 921560-2	NOVA CORPORATION OF ALBERTA (NOVA) FOR PERMITS TO CONSTRUCT ADDITIONAL FACILITIES TO NOVA WESTERN MAINLINE
D 93-3	910526 910289 910790 901972	SIMON AND MICHEAL SKINNER AMAX PETROLEUM OF CANADA INC. APPLICATIONS FOR REVIEW OR DECELOPMENT OF FACILITIES, WELLS, SPACING ORDER, AND HOLDINGS HAYTER FIELD - PROVOST AREA 910890 to 910905
D 93-4	921563	PROCEEDING RESULTING FROM A REQUEST BY NORTHWESTERN UTILITIES LIMITED FOR THE BOARD TO REVIEW DECISION D91-6 PURSUANT TO SECTION 42 OF THE ENERGY RESOURCES CONSERVATION ACT

D 93-5	921014 921026	APPLICATION BY AMOCO CANADA PETROLEUM COMPANY LTD. THE IMPERIAL PIPELINE COMPANY, LIMITED AND KOCH PIPELINES LTD. FOR PERMITS TO CONSTRUCT CRUDE OIL/ CONDENSATE/BLENDED BITUMEN PIPELINES AND RELATED FACILITIES IN SUNDRE/EDMONTON AREAS
		APPLICATION BY NORTHWESTERN UTILITIES LIMITED FOR A REVIEW AND VARIANCE OF DECISION D91-6
Memorandum	921321	APPLICATION TO AMEND APPROVAL NO. 5641 MILDRED LAKE OIL SANDS OPERATION SYNDRUDE CANADA LTD.
D 93-6	921683	Chancellor energy resources inc. APPLICATION TO CONSTRUCT AND OPERATE A SWEET GAS PROCESSING PLANT IN THE STEWART FIELD
D 93-7	931014	SHELL CANADA LIMITED APPLICATION TO EXPAND BLOCK STORAGE AT SHANTZ SULPHUR FACILITY SW 1/4-35-31-4W5M
D 93-8	901312 931123- 931125 931149	RANCHMEN'S RESOURCES LTD. REOPENING OF HEARING OF APPLICATION NO. 901312 APPLICATIONS FOR APPROVAL TO CONSTRUCT AND OPERATE WELL SITE FACILITIES PERMITS TO CONSTRUCT PIPELINES KNOPCIK FIELD
Memorandum	931689 931696	APPLICATION FOR WELL LICENCE MOOSE MOUNTAIN AREA HUSKY OIL OPERATIONS LTD. 931746-931748
D93-9	931497- 931504 931506 931671 931467-931471, 931670	HOME OIL COMPANY LIMITED IMPERIAL OIL RESOURCES LIMITED RENAISSANCE ENERGY LTD. APPLICATIONS FOR WELL LICENCES AND PIPELINE PERMITS COLD LAKE, LEISMER AND LEMING FIELDS
Memorandum	931598	APPLICATIONS FOR WELL LICENCE PROCUPLINE HILLS-WHALEBACK RIDGE AREA AMOCO CANADA PETROLEUM COMPANY LTD.
Memorandum	931598	AMOCO CANADA PETROLEUM COMPANY LTD. WHALEBACK RIDGE AREA ADVANCE LOCAL INTERVENER FUNDING
D 94-1	931052	APPLICATION FOR A WELL LICENCE RICINUS FIELD MOBIL OIL CANADA, LTD.
D 94-2	931689 931696 931746-931748	APPLICATIONS FOR WELL LICENCES MOOSE MOUNTAIN AREA HUSKY OIL OPERATIONS LTD.
D 94-3	931225	CARDINAL RIVER COALS LTD. PERMIT EXTENSION TO INCLUDE 50-A8 PIT
D 94-4	931807 931818 940304 to 940308	APPLICATIONS FOR ESTABLISHING A HOLDING, WELL LICENCES AND RELATED PIPELINE AND PRODUCTION FACILITIES DISCOVERY WEST CORP.

D 94-5		SYNCRUDE CONTINUED IMPROVEMENT AND DEVELOPMENT PROJECT MILDRED LAKE OIL SANDS PLANT
D 94-6	931148 940446 to 940450	CONWEST EXPLORATION COMPANY LIMITED
D 94-7	931409	BALOIL RESOURCES LTD. ZAMA LAKE POWER PLANT
D 94-8	931598	APPLICATION FRO AN EXPLORATORY WELL AMOCO CANADA PETROLEUM COMPANY LIMITED WHALEBACK RIDGE AREA

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

POLARIS PETROLEUMS LTD.
APPLICATION FOR A WELL LICENCE
PROVOST FIELD

Decision D 91-1
Application 910018

1 INTRODUCTION

1.1 Application and Intervention

Polaris Petroleums Ltd. (Polaris) applied to the Energy Resources Conservation Board (Board or ERCB), pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well from a surface location in legal subdivision 5 of section 31, township 37, range 3, west of the 4th meridian (SW 1/4 Sec 31) to a bottom-hole location in legal subdivision 8 of section 36, township 37, range 4, west of the 4th meridian (SE 1/4 Sec 36). The purpose of the well would be to obtain oil production from the Dina Formation.

An intervention opposing the application was filed by Mr. W. P. Nelson (Mr. Nelson) who owns the southeast quarter of section 36. Mr. Nelson's intervention was based largely on the effects the proposed well may have on the environment.

1.2 Hearing

A public hearing of the application was conducted on 12 February 1991 at Provost, Alberta, before F. J. Mink, P.Eng., B. F. Bietz, Ph.D., and N. G. Berndtsson, P.Eng. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Polaris Petroleums Ltd. (Polaris) J. D. Rooke	F. O. Ceh (of Tempest Developments Ltd.) K. Duhaime (of Jim Lore & Associates Ltd.) J. W. Lundquist R. J. Snow, P.Geol. T. L. Dobrowski, Ph.D. (of Piteau Engineering Ltd.)
W. P. Nelson (Mr. Nelson) W. P. Nelson	C. Prediger R. Hanson W. Hanson W. P. Nelson M. Lawrason
Energy Resources Conservation Board staff C. S. Richardson	

1.3 Background

The proposed well is located in an area where a number of Dina oil pools have been discovered. The proposed well is exploratory in nature and if drilled and successful, would be expected to encounter a new pool.

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the surface location of the well, and
- the environmental impact of the well.

3 NEED FOR THE WELL

Polaris submitted that there was a need for the well in order that it may fulfil its obligation under a farm-out agreement, in order to test its geological interpretation, and in order to fulfil its corporate objectives to explore for oil and gas.

Mr. Nelson did not dispute Polaris' chosen bottom hole location for the well nor did he dispute the need for the well.

The Board notes that Polaris' geologic interpretation was not challenged and it accepts the need for the well. The Board believes that Polaris should have the opportunity to explore for oil and gas, unless circumstances exist that would make it contrary to the public interest.

4 SURFACE LOCATION OF THE WELL

Polaris had approached Mr. Nelson prior to applying for its well licence in order to secure a surface lease on the SE 1/4 Sec 36 for a vertically drilled well. The terms of the surface agreement requested by Mr. Nelson were unacceptable to Polaris. Polaris also re-evaluated the available seismic data, determined that a more optimal alternative was to directionally drill a well to approximately the same initial bottom-hole location from surface location on the SW 1/4 Sec 31, and secured a surface lease from the owner of the land.

Polaris submitted that if the proposed well were drilled and successful, it would apply to the ERCB for reduced spacing to fully develop the pool. It stated that the proposed surface location would provide an optimum location for the drilling of additional wells from a common surface location (pad), which would minimize surface impacts. Polaris argued that in consideration of its re-evaluation of available seismic data, the applied-for surface location was geologically optimal. It was very much concerned about drilling on the SE 1/4 Sec 36 because it was Mr. Nelson's preference that additional wells not be drilled from a common multi-well pad.

Mr. Nelson submitted that he did not refuse entry to Polaris for a well location on the SE 1/4 Sec 36 and that Polaris had not presented any compelling reasons why it could not drill the proposed well from a surface location on the SE 1/4 Sec 36. He stated that a location on the SE 1/4 Sec 36 would be preferable to him because the well could be drilled vertically and would not impose the environmental risks that would be associated with drilling the well directionally from the applied-for location. He argued that the conditions he wished to attach to a surface lease agreement with Polaris would further reduce environmental impacts and that part of the reduction of impacts would come from maintaining individual vertically drilled well sites.

The Board notes that Polaris did not wish to amend its application to provide for an alternative site on the SE 1/4 Sec 36 and as such, must establish the acceptability of the applied-for surface location for the well in SW 1/4 Sec 31. The Board notes that a surface lease has been secured by Polaris for the applied-for location and that the location may be utilized in the future for the drilling of additional wells. The Board disagrees with Mr. Nelson's position that individual vertically drilled well sites would have less environmental impact than a multi-well pad location. Its reasons for this position are discussed further in this report. The Board also does not accept that a short reach directional well, such as that proposed by the applicant, would result in any incremental environmental risk. The Board thus finds that the applied-for surface location for the well is acceptable, provided that other environmental impacts can be reduced or mitigated to acceptable levels.

5 ENVIRONMENTAL IMPACTS OF THE WELL

Polaris submitted that the drilling and operation of the proposed well would have minimal impact on the environment and no impact on Mr. Nelson. Respecting Mr. Nelson's concern for air quality, Polaris proposed that if the well were successful, it would utilize a single-well battery equipped with the following:

(a) a two-phase separator with an overhead gas tie-in to the flare or incinerator stack,

(b) production tanks with a gas boot connected to a flare or incinerator stack,

(c) a minimum 40-foot flare stack with a continuous propane pilot, and

(d) a pumpjack engine that will automatically shut down if the flare stack pilot is unlit because of lack of fuel.

Polaris noted that this proposed facility would be similar to other single-well Dina batteries that have been approved by the ERCB in the Cadogan/Sounding Lake area and that the nearest residence to the proposed well is approximately 1.5 kilometres (km) away.

To ensure groundwater protection, Polaris proposed to berm the lease, contain all drilling and well fluids in steel tanks and utilize a remote sump, install a conductor pipe pile driven to 12-18 metres (m), set a minimum of 180 m of surface casing to isolate shallow aquifers, drill with fresh water and natural clay, cement the surface and production casing from the bottom of the casing to surface, and not impede surface drainage. Respecting Mr. Nelson's water well located on the SE 1/4 Sec 36, Polaris believed it was not necessary to test the well for quality or flow rate. Because of the measures it proposed in order to protect groundwater and the distance from the proposed well to the water well (500 m), the position of Polaris was that there would be no impact on the water well.

With regard to surface impact, Polaris submitted that there would be no impact on any of Mr. Nelson's land. In order to minimize the impact the proposed well would have on the land surface, Polaris intended to strip only an estimated 30 per cent of the total lease area, and stockpile the soil, recontour and reseed the lease using non-native species as soon as possible after drilling operations, control weeds, and avoid the use of soil sterilents. During drilling, no permanent access road would be constructed.

Mr. Nelson submitted that the environmental impacts from the proposed well would not be acceptable to him. He stated that the well would cause odour problems, the lease area would not be easily reclaimed, and, if the site were used for a multi-well pad, the site would not be reclaimed for a long period of time. Furthermore, the stockpiled soil would be eroded, groundwater would be affected by drilling if the well-bore left gas zones in communication with aquifers, particularly in the case of poor cement practices, and if the well were successful, the resultant single-well battery would affect air quality in the area by the emission of hydrogen sulphide (H_2S) and sulphur dioxide (SO_2). To illustrate these problems, Mr. Nelson cited difficulties that area ranchers and farmers had experienced with other operations in the Sounding Lake area approximately 4 km southwest of the proposed well.

The Board notes that because the proposed well is located on land not owned by Mr. Nelson, many of the surface impacts that were of concern would not be imposed on Mr. Nelson. Given the undertaking by Polaris, the Board does not believe it is necessary to apply any further restrictions on Polaris regarding site preparation, soil stockpiling, or reclamation procedures. Further, the Board notes that many of the commitments made by Polaris improve on normal oilfield practices. Polaris will minimally strip the lease area, it will utilize steel tanks to contain fluids, and it will dispose of these drilling fluids at a remote sump. The Board also notes that if the well is successful, Polaris would intend to utilize the site as a multi-well pad for further drilling. This is in accordance with past decisions of the ERCB and the Board's position that surface disturbance be reduced to a minimum through the consolidation of surface facilities whenever such consolidation is reasonably cost-effective and/or appropriate.

The Board believes that Polaris' commitments to contain emissions are generally adequate. However, the Board will ask that Polaris report back to the ERCB regarding the feasibility of using trucks equipped to reduce H_2S emissions. The Board notes Mr. Nelson's concerns regarding other operations in the area but it cannot assume that Polaris would conduct its operations at the proposed well in an imprudent fashion. The Board expects Polaris to live up to the commitments made in its application.

Given the evidence, the Board does not believe the proposed well would have an adverse effect on groundwater in the area. It is the Board's view that the cementing of both the surface and production casing to surface will provide adequate protection of groundwater and if cement returns are not obtained at surface, a remedial cementing program shall be required by the Board. The Board accepts the additional mitigative measures proposed by Polaris to protect groundwater in the area, including the cementing of surface casing to a minimum depth of 180 m and believes that the chances for damage to Mr. Nelson's water well in the SE 1/4 Sec 36 are very remote. In this regard, the Board will not require Polaris to monitor the local groundwater regime or to test Mr. Nelson's water well.

6 REGIONAL ISSUES

The Board notes the many concerns expressed by Mr. Nelson and his neighbours respecting regional concerns for air, soil, and groundwater protection. Although these issues are not the subject of this report, the Board believes the concerns warrant further attention. The Board is aware that a group of senior industry representatives are working with representatives of the public from the Provost area to determine how regional concerns should be addressed. The Board will ask that group to consider the matters raised at this hearing and to review and comment on the status of the oil and gas development in the Sounding Lake area with particular attention to the timing of reclamation of well sites, types of production facilities being used, their effectiveness in containing emissions, and the endeavours of the operators to minimize surface disturbance. The issue of groundwater protection will be brought to the attention of the Groundwater Branch of Alberta Environment.

7 DECISION

The Board has reviewed the positions of the parties and the facts with respect to this matter and believes that there is a need for the well. It believes that the well can be drilled and operated as applied for with no impact on Mr. Nelson's land and cattle operation and with minimal impact on the local environment. The Board approves Application 910018 and a well licence will be issued.

DATED at Calgary, Alberta, on 1 March 1991.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

APPLICATIONS BY SHELL CANADA LIMITED FOR PERMITS TO CONSTRUCT PIPELINES TO TRANSPORT SOUR GAS AND FUEL GAS IN THE WATERTON AREA

Interim Decision D 91-2
Applications 901631 and 901632

The Board has considered the need for a preliminary decision regarding the proposed stream crossings. In doing so, the Board has examined the evidence presented at the hearing held 28 March 1991.

The Board accepts Shell's proposed stream crossing locations and notes that no concerns were raised by interveners regarding the route selected by Shell. The Board believes Shell's proposed construction method will adequately protect the stream environment by minimizing the extent, frequency, and duration of disturbance, including siltation. The Board is confident creek bed siltation can be kept at acceptable levels, but to ensure undue impact is avoided believes Shell should have environmental support staff supervise the construction of the crossings.

Accordingly, the Board is prepared to approve the pipeline creek crossings as applied for by Shell and approved by Forestry, Lands and Wildlife, subject to receipt of the required approval of the Minister of the Environment respecting environmental matters.

A further report providing detailed reasons for the decision and discussing the remainder of the pipeline application will be forthcoming.

DATED at Calgary, Alberta, on 9 April 1991.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D.*
Board Member

W. G. Remmer, P.Eng.
Acting Board Member

---

* B. F. Bietz was unavailable for signature but concurs with the contents and with the issuing of this decision.

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

APPLICATIONS BY SHELL CANADA LIMITED
FOR PERMITS TO CONSTRUCT PIPELINES
TO TRANSPORT SOUR GAS AND FUEL GAS
IN THE WATERTON AREA

Decision D 91-2
Applications 901631 and 901632

1 INTRODUCTION

1.1 Applications

Pursuant to Part 4 of the Pipeline Act, Shell Canada Limited (Shell) submitted an application for a permit to construct approximately 6.4 kilometres (km) of 168.3-millimetre (mm) outside diameter pipeline to transport sour gas, with a maximum hydrogen sulphide (H_2S) content of 240 moles per kilomole, from an existing well (Waterton 55) located in legal subdivision 2, section 25, township 4, range 2, west of the 5th meridian (Lsd 2-25-4-2 W5M), to a tie-in point in the existing Waterton field gathering system located in Lsd 9-2-5-2 W5M. This application also included four spare creek crossings of Whitney Creek or its tributaries.

Shell also submitted a separate application for a permit to construct approximately 2.6 km of 60.3-mm outside diameter pipeline to transport fuel gas from the existing system in Lsd 10-26-4-2 W5M to the Waterton 55 well. This application also included three spare creek crossings of Whitney Creek or its tributaries.

The proposed route of the pipelines is shown on the attached map.

1.2 Hearing

A public hearing of the application was held in Pincher Creek, Alberta, on 28 March 1991 before Board Members F. J. Mink, P.Eng., B. F. Bietz, Ph.D., and Acting Board Member W. G. Remmer, P.Eng.

At the outset of the hearing a number of interveners requested that the Board adjourn to a later date in order to permit those parties additional time to prepare for the hearing and to obtain expert witnesses. The applicant argued that it had already made significant efforts to inform potential interveners of its proposed plans well in advance (i.e. several months) of the notice of hearing. The Board was of the view that although there had been a relatively short period of notice between advertising the hearing and the date of the hearing, given the ongoing consultation prior to the hearing and given the nature of the application, the parties had had adequate time to prepare; therefore, it denied the request for adjournment.

Participants at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) R. B. Low	F.H.S. George, P.Eng. D. Lang D. A. Mead, Ph.D. W. A. MacLeod, P.Eng. T. Magowan
Pincher Creek Chapter of the Alberta Wilderness Association (AWA) W. Judd	W. Judd J. Tweedy
Diamond Hitch Outfitters (Diamond Hitch) Ian Cartwright	M. Judd
Federation of Alberta Naturalists (FAN) H. R. Gardner	H. R. Gardner
Lethbridge Fish and Game Association R. Stewart	R. Stewart
Crown of the Continent Society H. Snyder	H. Snyder
J. Huntley	J. Huntley
D. H. Sheppard, Ph.D.	D. H. Sheppard, Ph.D.
Energy Resources Conservation Board staff C. J. C. Page A. Larson, P.Eng.	

R. E. Wolf submitted an intervention but did not appear at the hearing.

The Lethbridge Fish and Game Association stated its concerns for the preservation and conservation of all wildlife but chose not to take a position on the application before the Board. The Crown of the Continent Society appeared at the hearing to encourage the consultative process but also chose not to take a position on the application before the Board.

The Board notes that at the time of the hearing Shell had obtained a pipeline agreement (PLA) and a water resources permit from Alberta Forestry, Lands and Wildlife (FLW). A mineral surface lease (MSL) was also issued in 1987 by FLW for this area to provide lands for the well site, access road, and utility corridor.

1.3 Interim Decision

The Board issued an interim decision on 9 April 1991 approving the creek crossings subject to receipt of the required approval of the Minister of the Environment respecting environmental matters. A copy of Interim Decision D 91-2 is attached to this report. This report provides detailed reasons for that decision and considers the remainder of the pipeline application.

2 ISSUES

The Board believes the issues are

- the need for the pipelines,
- the proposed route,
- the environmental impacts, and
- the consultative process.

3 NEED FOR THE PIPELINES

Shell stated that the proposed pipelines are needed to transport the production from the Waterton 55 well into the existing gathering system to the Shell Waterton gas plant in order to fulfil the Shell Waterton gas contract with Alberta and Southern Gas Co. Ltd. Extra creek crossings were considered desirable to avoid the need for any future disturbances of the creek bed should it become necessary to replace the main pipeline segments during the operating life.

The interveners questioned the need for immediate production of the Waterton 55 well but they agreed that the pipelines would be needed if the well was to be produced. The majority of interveners believed that pipeline construction should be delayed until further fish and wildlife studies could be completed in order to determine the environmental impact of the proposed pipelines and facilities associated with the well. Mr. Judd of Diamond Hitch questioned Shell's immediate need for the gas and stated that environmental effects must be considered first.

FAN intervened on behalf of the application. It believes that expeditious depletion of the gas reserves is desirable, so that the area can be reclaimed to its natural state with minimal delay. FAN also believes that it is beneficial to have petroleum resource development taking place during periods of co-operation between industry and public groups concerned with environmental protection.

The Board accepts Shell's need to maintain deliverability to the plant to fulfil its gas contract, and recognizes the right of Shell to produce the Waterton 55 well unless the associated environmental impacts are found unacceptable. Therefore, the Board concludes that the pipelines are needed.

4 THE PROPOSED ROUTE

Shell proposed to place both pipelines in a single ditch. The upper portion would run within an existing 20-metre (m) right of way (ROW) immediately adjacent to the current access road from the well to Lsd 10-26-4-2 W5M. The remainder of the pipeline would be placed in an existing pipeline ROW to Lsd 9-2-5-2 W5M. Shell stated that its proposed route would minimize any impacts caused by the construction of the pipelines, by minimizing the need for additional ground disturbance or clearing. Shell stated that it would adopt the 1987 environmental overview report submitted as evidence in the Waterton 55 well licence application hearing, D 88-16[1]. This report addressed the issues of pipeline routing, construction, and abandonment.

The interveners agreed that if the pipeline were to be built the proposed route along an existing ROW would be the most desirable.

The Board accepts that in general the proposed pipeline route was chosen so as to prevent incremental environmental impacts. The Board finds the proposed routing acceptable provided no other unacceptable environmental impacts become evident.

5 ENVIRONMENTAL IMPACTS OF THE PIPELINES

5.1 Whitney Creek Crossings

5.1.1 Views of Shell

Shell took the position that many of the environmental issues associated with construction of the pipelines had been dealt with in the previous well licence hearing. Its general view was that any environmental effects resulting from adding, in their opinion, a relatively small diameter pipeline over a relatively short distance should be addressed only insomuch as they were incremental to existing impacts.

Shell stated that the proposed route would require a total of four stream crossings on Whitney Creek. Shell proposed to trench up to the stream edge and then insert foam plugs. The pipeline would be preassembled on the shoreline. Trenching of the creek would be carried out using a backhoe; Shell expected the narrow width of the creek would avoid the need for the backhoe to operate within the creek. Material removed during trenching would be placed on shore. Once trenching was complete, the plugs would be removed, the pipeline laid across the creek, and the trench refilled with selected backfill, including large rocks at the surface. Shell estimated crossing in this manner would require, excluding preparation time, 1 to 1.5 days to complete.

Shell indicated that it had considered other techniques, such as fluming (i.e. diverting) the creek around the work site, but had rejected these methods as they had as much or more risk of introducing sediment into the creek. On questioning by the Board, Shell confirmed that the construction window of 5 April to 1 May established by FLW for the stream crossings was narrow and would be difficult to meet. Shell's understanding of the need for the window was to protect native cutthroat trout and bulltrout from disturbance and reduced water quality due to increased sediment loadings.

Shell believed that the proposed pipeline crossings of Whitney Creek would create only limited short-term siltation because the bed of the stream is mostly rocks and gravel over bedrock at the crossing sites. Shell stated that long-term siltation would be prevented by the reclamation techniques described in the environmental overview report for the project and by regular inspections of the crossings during pipeline operations.

---

[1] ERCB Decision D 88-16, **Shell Canada Limited Application for a Well Licence Waterton Field**, 22 December 1988.

5.1.2 Views of the Interveners

The local chapter of the AWA echoed many of the general concerns raised by the other interveners. Protection of local bulltrout and cutthroat trout populations was given a high priority. Both species have low numbers in the province, which results in part from their tendency to hybridize with other species, particularly rainbow trout, and so protection of relatively isolated, genetically pure stocks was very important. The AWA stated that fluming should be the preferred method of crossing and believed that Shell should do more work to develop an environmentally sensitive method of crossing the creek. Mr. Judd also had serious concerns regarding the potential impacts of silt from the stream crossings on native cutthroat and bulltrout populations, and felt that Shell had not adequately considered alternative stream crossing methods. Dr. Sheppard stated that the method of least disturbance should be used to construct the creek crossings.

5.1.3 Views of the Board

The Board accepts Shell's description of the creek bed substrate materials and it believes that Shell's method of construction would minimize the impact of the proposed pipeline crossing on the creek. The Board notes that if Shell were to use a fluming method, the creek would be disturbed twice and it would take extra time to complete the crossing. The Board also notes that FLW has approved Shell's method for the creek crossing. The Board is confident that Shell, through careful control of its construction activities, can carry out the pipeline crossings in such a way that creek bed siltation will be reduced to acceptable levels, and that impacts on native trout populations, if any, can be limited to a single construction season. The Board is concerned that unnecessary impact on the creek should be avoided; therefore, it believes Shell should have environmental support staff present during the construction of the pipelines to avoid undue impact.

5.2 Fish and Wildlife

5.2.1 Views of Shell

Shell stated that it did not expect the proposed pipelines to have a significant impact on fish habitat or wildlife in the area. Shell stated that any impact which did occur would be during construction, and this would be over a relatively short time of 6 to 8 weeks. Shell also stated that as part of its commitment during the drilling of the well, it had commissioned a study of the fish habitat in Whitney Creek. The study identified over-wintering habitat as the limiting feature of Whitney Creek for trout. As a result of this study Shell undertook a habitat enhancement program and built a number of over-wintering pools in the creek. Shell also carried out a water quality testing program and found no correlation between suspended solid levels and construction and drilling activity. With respect to wildlife impacts, Shell had commissioned an area elk study and is now a participant in a 3-year regional elk study.

5.2.2 Views of the Interveners

Mr. Judd and Mrs. Huntley visited the well site shortly before the hearing and expressed concerns regarding ongoing impacts on Whitney Creek associated with Shell's present operation. At the time of the visit, a service rig was working on the well and there was a great deal of traffic in the area. Mr. Judd had concerns regarding longer-term siltation resulting from run-off from the access road and due to what he believed to be Shell's failure to adequately revegetate cuts and back slopes along the access road. He also noted areas where run-off was contaminated with oils or other chemicals from the existing well site and access road.

Of major concern to Mrs. Huntley was the potential for contaminants such as grease and hydraulic fluids as well as silt from the access road to migrate into Whitney Creek. She was also concerned about run-off from, and debris on, the well site. It was her view that if these issues were not addressed, these impacts could continue over the life of the well.

The AWA believed the traffic in the area was also contributing to siltation of the creek bed, thereby potentially affecting fish habitat. It was suggested that access to the area be limited and the well be shut in during the winter months to avoid activity on the road and possible impacts on the creek. The AWA stated that the Board should consider the evidence of the biologists given at the well licence hearing (D 88-16) regarding Whitney Creek.

Mr. Judd also raised a number of general concerns with regard to the Whitney Creek development. He noted that during the original well licence hearing, the issue of the pipeline was not addressed specifically. It was his view that Shell had not lived up to a number of commitments made in the original application, and therefore should not be permitted to tie in the Whitney Creek well at this time. Furthermore, he believed that Shell had the responsibility to demonstrate that no impacts on wildlife or fish had occurred as a result of drilling the well before it should be allowed to tie in the well. Mr. Judd noted that while Shell was engaged in a long-term study of elk in the region, the study did not address impacts on other species of wildlife. Diamond Hitch believes that an interim report on the elk study would be beneficial and it should be reviewed before the pipeline is installed. Mr. Judd and Mr. Sheppard both expressed concern for grizzly bear populations in the area and suggested they also be considered in any future studies.

The AWA expressed concerns regarding Shell's fish habitat enhancement program. It expressed doubts as to the effectiveness of any program to enhance upon nature and believed the program could actually have damaged stream habitat.

5.2.3 Views of the Board

The Board also has some concern regarding run-off from the access road and road ditch into Whitney Creek. The Board notes that during the site visit made by Mrs. Huntley and Mr. Judd, there was a service rig working on the well, and believes that the activity in the area at the time of the visit was greater than what would be expected during normal operation of the well. The Board notes that as a condition of the MSL, Shell is required to restrict access to the Whitney Creek area by means of a locked gate placed on the bridge nearest to the 10-26 well and manning of the gate during the pipeline construction. The Board believes that restricted travel, attention by Shell personnel to design appropriate drainage control systems, and routine inspection of the effectiveness of this control should avoid any material impacts on Whitney Creek.

The Board is satisfied that neither the pipelines nor the operation of the well will have long-term effects on fish and wildlife in the area and believes that Shell can resolve shorter-term concerns with proper construction techniques and operational management. The Board believes that additional fish and wildlife studies are not necessary to reach a decision on the applied-for pipelines. The Board notes the commitment by Shell to long-term regional wildlife studies, and that Shell will continue to review the study objectives, methodology, and the species being considered. The Board views control of motorized access to the valley as a key issue in protecting wildlife, and believes Shell's program will be effective.

5.3 Reclamation

5.3.1 Views of Shell

Shell stated the proposed pipelines would be installed in a single trench within the road ditch and in an existing pipeline ROW. In order to control erosion, Shell indicated that it planned to revegetate the disturbed pipeline ROW as soon as possible. Shell was considering the use of native plant species to revegetate but indicated that this needed to be balanced against the need for rapid germination and establishment of vegetative cover in order to reduce erosion risk. Shell was working with FAN to select the appropriate seed mixture. Shell also indicated it planned to use straw bales as barriers on steeper slopes to reduce erosion potential and agreed to implement a regular inspection program to monitor for evidence of erosion following construction.

Shell indicated that a power line extending from the well site at 10-26 to the 2-25 well would be required, and estimated it would need to clear an additional 6 m in width over 1900 m of ROW. Shell noted that the MSL does deal with reclamation issues and that the environment overview report deals with issues of topsoil stripping, reclamation, and contouring.

5.3.2 Views of the Interveners

All the interveners questioned if additional tree clearing was really necessary. The interveners also stated that native species should be used in revegetation. Mr. Judd was sceptical with regard to Shell's claim regarding ROW width. It was his view that the existing access road has already required an excessive amount of clearing, and he expected more clearing would take place during pipeline and power line construction. Dr. Sheppard stated that straw bales to mitigate erosion were suitable for the construction phase but believed a more permanent barrier such as rocks would be needed to prevent erosion at a later date. Another method would be to replace the bales as they deteriorated.

5.3.3 Views of the Board

The Board believes the conditions applied to the original development permit for the well and access road should result in timely and sound reclamation of the well site, road, and pipeline ROW. The Board supports the concept of minimizing the amount of tree clearing wherever possible, and requests Shell to take all possible measures to ensure that only necessary ROW clearing occurs. The Board notes that most of the clearing will occur because of the construction of the power line and it expects Shell to consult with the power company to ensure that minimal tree clearing occurs. The Board also directs Shell to have a company representative present when any clearing is to be completed to ensure that minimal clearing occurs. The Board believes that there is some advantage to installing the pipeline at this time so that revegetation of the access road ROW would only have to occur once. The Board supports the use of native species for revegetation where applicable and believes the approach adopted by Shell to work with FAN and FLW will provide a suitable solution.

5.4 Conclusion

In summary, the Board is satisfied that the degree of environmental impact from the applied-for pipelines would not warrant denial of the application.

6 CONSULTATIVE PROCESS

The Board notes that the applicant has developed a significant consultative process in the region, and that all parties to this hearing, despite their objections to this application, appeared to value and appreciate this process. The Board also strongly supports this process and believes it has resulted in a number of local issues being effectively addressed outside of the hearing process.

It is the Board's view that this process should continue in the Waterton area, and that all participants should be commended for their efforts to date. While consultation does not in any way preclude the right of any party to request a public hearing, the Board continues to be convinced that the consultation process has been a net benefit to all involved parties. The Board expects that the consultative process represents an ideal opportunity for all affected parties to resolve problems related to the construction and operation of the pipeline.

7 DECISION

The Board approves the two pipeline applications made by Shell Canada Limited.

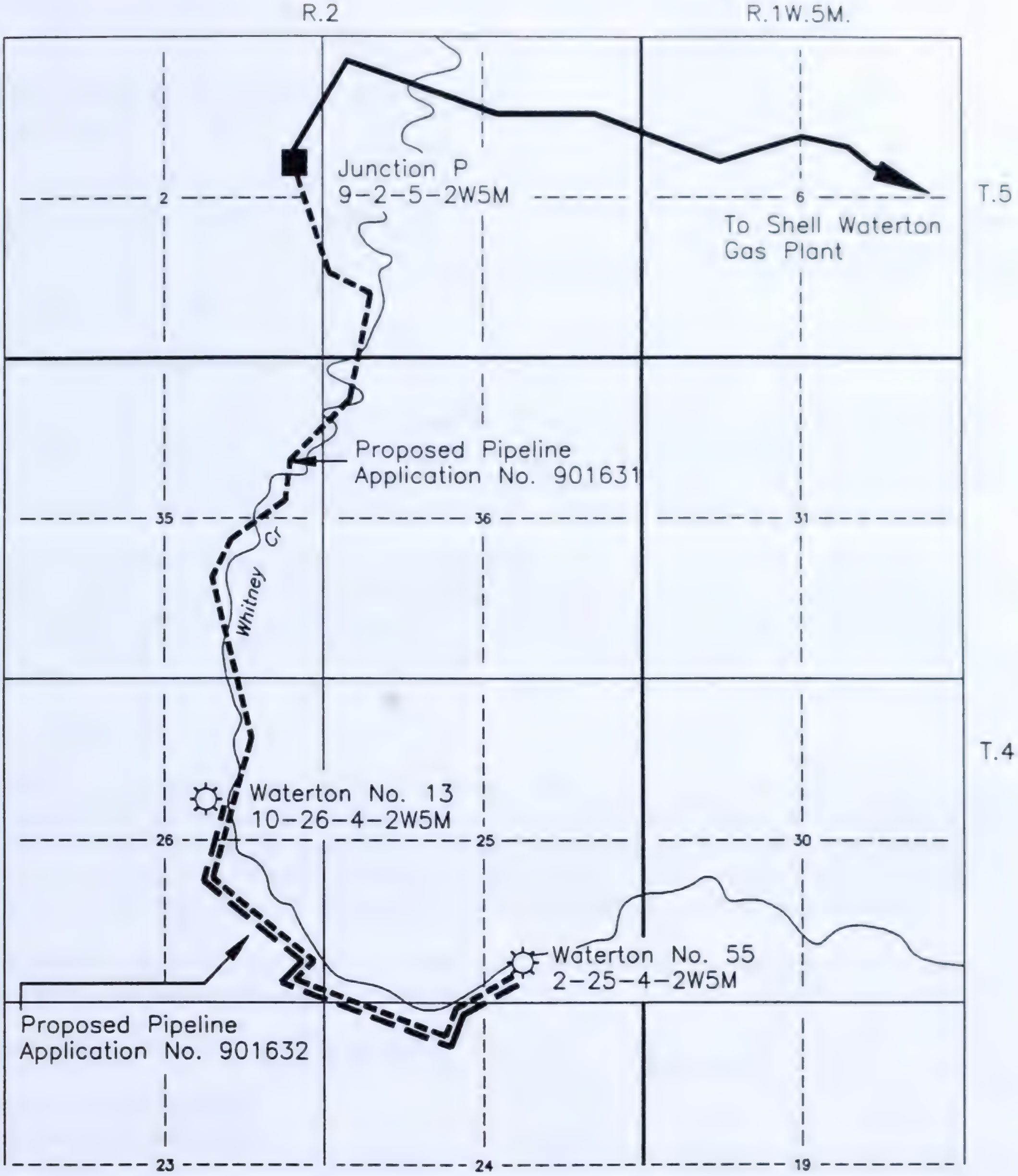
DATED at Calgary, Alberta, on 21 May 1991.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D.
Board Member

W. G. Remmer, P.Eng.
Acting Board Member



PROPOSED PIPELINES – WATERTON AREA

Applications No. 901631 and No. 901632

Shell Canada Limited

D91-2

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

POINTER EXPLORATION CORP.
APPLICATION FOR A WELL LICENCE
BANTRY FIELD

Decision D 91-3
Application 910227

1 INTRODUCTION

1.1 Application and Intervention

Pointer Exploration Corp. (Pointer) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well to be known as POINTER ET AL BANTRY 4-8-19-13 (the proposed well) to obtain production from the Ostracod or Pekisko Formation. The proposed well would be drilled in legal subdivision 4 of section 8, township 19, range 13, west of the 4th meridian (4-8).

Interventions opposing the application were submitted by Mr. and Mrs. Darrel and Evelyn Murray (the Murrays) and Mr. and Mrs. Peter and Lavern Buhler (the Buhlers). The County of Newell No. 4 did not file a submission but appeared at the hearing. It stated that it recognized the concerns of both Pointer and the interveners and requested that the Board carefully consider the concerns and rights of all parties in its decision.

1.2 Hearing

A public hearing of the application was held in Brooks, Alberta, on 10 April 1991 before Board Member B. F. Bietz, Ph.D., and Acting Board Members T. F. Homeniuk, P.Eng., and N. G. Berndtsson, P.Eng., (the Board). At the outset of the hearing it was agreed by all parties that a site visit to the proposed well location and adjacent rural residential subdivision would be appropriate. The site visit was conducted on 10 April 1991 and was attended by Pointer, the Murrays, the Buhlers, the Board, and Board staff.

The attached figure shows the proposed well location, the rural residential subdivision, current and potential well spacing patterns, and other features of the area.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Pointer Exploration Corp. (Pointer)	M. V. Wolfli, P.Eng.
H. R. Hansford	J. A. Bolter, P.Geol.
D. Murray	D. Murray
E. Murray	E. Murray
P. Buhler	P. Buhler
L. Buhler	L. Buhler
P. J. Madden	W. G. Hegel, P.Eng. of Nez Perce Engineering & Management Ltd.
	R. Kibsey
County of Newell No. 4 (the County)	Walter Wells
Energy Resources Conservation Board staff	
C. S. Richardson	

1.3 Background

The proposed well would be located in the Bantry Field. The field comprises an area of approximately 320 sections where oil and gas development has occurred since the early 1950s. Within an area of 9 square miles surrounding the proposed well there have been approximately 132 wells drilled to date, the majority of which were drilled in the late 1960s and throughout the 1970s. Of these wells, approximately 59 per cent are gas wells, 14 per cent are oil wells, and 27 per cent are abandoned wells or wells of other status. The current oil well spacing on the southwest quarter of section 8, township 19, range 13, west of the 4th meridian (SW 1/4 Sec 8) is one oil well per quarter section (64 hectares), with the target area located in the northeast legal subdivision (Lsd) (Board spacing unit Order No. SU 800). The oil well spacing on lands immediately west of the proposed well is one well per two Lsds (32 hectares), with the target areas being the northwest quadrant of the southwest or northeast Lsds of the quarter section (Board spacing unit Order No. SU 1698). At the hearing, Pointer indicated that, if the proposed well is successful, it would intend to apply to the ERCB for a change in oil well spacing on the SW 1/4 Sec 8 to one well per two Lsds. This would be consistent with established spacing in the area and would provide for an additional on-target well in Lsd 6 of section 8.

Land use in the area of the proposed well is varied. As shown in the attached figure, the SW 1/4 Sec 8 contains twelve residential lots around the periphery and approximately 20 hectares of irrigated hay land in the central portion of the quarter section. The North Bantry Irrigation Canal passes through the quarter on the east side and supplies water to the surrounding irrigated farmlands. A compressor plant is located on the northwest edge of the quarter. Several oil and gas wells and related production facilities are present in the surrounding region.

Because of the proximity of the proposed well to the rural residential subdivision, Pointer provided notification to area residents of its plans to drill the well. Pointer also met with residents to attempt to identify and address any concerns they may have respecting the proposed well. The concerns expressed included the potential for odours, increased traffic, noise, negative aesthetic impact, reduction of property values, and safety.

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the location and impacts of the well, and
- alternative oil target areas and future oil well spacing.

3 NEED FOR THE WELL

3.1 Views of the Applicant

Pointer submitted that there is a need for the proposed well in order that it may earn an interest, in keeping with its agreement with the mineral owner, in the reserves that may underlie the SW 1/4 Sec 8. It stated that drilling the well would benefit the local economy and the participants in the well, would provide local employment, and would provide a mineral tax to the province of Alberta.

3.2 Views of the Interveners

The interveners did not dispute the need for the well and recognized the general economic benefits that would result from drilling the well. They did, however, argue that the proposed 4-8 surface location is not necessary in order that Pointer reach a bottom hole location in Lsd 4.

3.3 Views of the Board

The Board accepts that there is a need for the well and notes that Pointer's geologic interpretation of the area was not disputed by the interveners.

4 LOCATION AND IMPACTS OF THE WELL

4.1 Views of the Applicant

Pointer submitted that it had carefully considered other surface locations for the proposed well and concluded that the proposed location would be the most appropriate. It stated that an optimal bottom hole location for a vertical well would result in a surface location closer to the interveners' residences. Recognizing that such a location would be unacceptable to the residents, and given that its geologic interpretation allowed some flexibility without significantly affecting the success of the well, Pointer chose the proposed surface location which is somewhat farther removed from the subdivision.

Pointer submitted that the well could be drilled and operated safely at the proposed site with minimal impact on the environment and neighbouring subdivision. It stated that in order to minimize impacts during drilling operations, which it estimated would require 7 days, it would adhere to ERCB noise guidelines (Interim Directive ID 88-1, Noise Control Directive) and would restrict noisy drilling operations, such as tripping and off-loading pipe, to daylight hours. It stated that it would control dust during drilling by keeping the access road and soil stockpiles wet. Pointer noted that it had made a commitment to its surface lessor to have the well drilled, completed, and pipelined prior to 15 May 1991, and that it intended to adhere to that commitment.

Pointer calculated a maximum hydrogen sulphide (H_2S) release rate for the well of 0.007 cubic metres per second (m^3/s) which equates to an emergency planning radius of 108 m from well centre. Since there are no residences within this radius, Pointer believed that an emergency response plan is not necessary. However, it is prepared, if necessary, to have in place an emergency "preparedness" plan similar to one it had used while drilling another well in the area.

Pointer contended that there would also be little impact on the neighbouring subdivision during the production phase of the well. Wells in the area typically flow for the first 1 to 2 years of production and thus require no pump for that period. It committed to pipeline the production from the well to a battery located in Lsd 2-12-19-14 W4M, thus eliminating the need for on-site tankage and a flare stack and greatly reducing the potential for odours. A low profile screw-type pump rather than a pumpjack would be used once the well required a pump. The wellhead and screw pump would be covered with a small structure such as a grain bin or beehive, in keeping with similar structures in the area. Pointer stated that the screw pump would be electrically driven to reduce noise. Power service to the site would be installed below ground.

Pointer submitted that traffic levels would be greatest during the drilling phase. Once the well is on production, its operator would visit the well in a pick-up truck on average twice per day for the first 6 months of production and once per day thereafter. Pointer indicated that well servicing would likely be required approximately once every 2 years.

Pointer indicated that, in response to suggestions from the interveners, it had also considered directionally drilling the well from surface locations in Lsd 5 of section 8 (5-8) and Lsd 1 of section 7 (1-7). A surface location at 5-8 would result in a horizontal displacement to the bottom hole location of 330 m. Pointer stated that the additional cost to directionally drill from the 5-8 location would be $48 000 for a dry hole, $65 620 for a completed well, and $71 240 for a completed well with the additional pipeline costs. Pointer further stated that the 5-8 directional well would require more frequent servicing at an annual additional operating cost of $12 000 because of increased rod wear. The increased operating cost would result in earlier abandonment of the well and a potential loss of 1 500 m^3 of oil recovery. It believed that it is not necessary to incur the additional costs associated with the 5-8 location as its mitigative measures would reduce impacts associated with the proposed well to a minimum.

With regard to the 1-7 location, approximately 150 m west of the proposed location, Pointer submitted that the additional cost to directionally drill from the 1-7 location would be about half the additional cost of directional drilling from the 5-8 location. However, it discounted the 1-7 location because it is not significantly farther away from the interveners' residences than the proposed location and vehicle traffic to 1-7 would need to use the same portion of the county road required for the proposed location. It did not believe that the minor reduction of impacts justified the increased cost associated with directionally drilling the well from the 1-7 location.

4.2 Views of the Interveners

The interveners submitted that both drilling the proposed well and operating it would have unacceptable impacts on their lifestyles, the safety of their families, and property values. Impacts would result from odours, noise, vehicle traffic, dust, potential oil spills, and reduced visual aesthetics. It was their position that odours are a problem with most oil wells and the proposed well would be no exception. Noise and vehicle traffic would increase in the area during both drilling and operating phases and cause dust and safety problems. The interveners expressed concern over the potential for the drilling operation to affect their domestic water supplies. They suggested that, if drilling fluids were squeezed from the sump onto the lease after drilling operations were completed, contaminants could enter the surface water system and migrate to nearby dugouts. The interveners submitted that the proposed oil well would adversely affect property values in the subdivision and would deter potential buyers from the area. They suggested that, if the well is drilled and is successful, it would be appropriate to require Pointer to submerge the wellhead, thus reducing the visual impact as much as possible.

The interveners submitted that, if the Board approves the proposed well, an emergency response plan should be in place for the drilling of the well in the event that any type of mishap occurred. While the interveners agreed that the planning radius submitted by Pointer did not include any residences, they noted that it did intersect the county road which provides the only access out of the area.

The interveners proposed the 5-8 location as an alternative surface location that would allow Pointer to drill directionally to the proposed bottom hole location without jeopardizing the economic viability of the well. They submitted that the 5-8 location would be sufficiently removed from their homes and they would fully support an application by Pointer for a 5-8 location. The interveners argued that the additional costs to directionally drill from the 5-8 location would be $35 000 for a dry hole and $45 000 for a completed well. Further, they argued that Pointer had not considered the potential cost savings of an eventual additional well at the 5-8 location. The interveners stated that, if the proposed well were drilled from the 5-8 location and Pointer pursued its plans to drill a well into Lsd 6-8, it could utilize the 5-8 surface location to drill the 6-8 well and save an estimated $20 000 by not requiring an additional surface lease and avoiding associated construction costs. The interveners submitted that the additional operating costs for the 5-8 location would be $5 000 per year for a rod-pumped well, which compared favourably with their estimate of an additional cost of $5 750 per year for a screw-pumped well at the 4-8 location, as proposed by Pointer.

The interveners agreed that the 1-7 location would only marginally reduce impacts and that it is not an acceptable alternative.

4.3 Views of the Board

To assess the appropriateness of a location for the proposed well the Board considered how the interveners would be affected, whether other property owners in the area would be affected, and what the effect would be on the environment. It also considered what mitigative measures, if any, are available to reduce any impacts to an acceptable level.

With regard to drilling impacts, the Board notes that drilling the well is expected to be completed in approximately 7 days and that any impacts associated with drilling would be reasonably temporary in nature. The Board accepts Pointer's commitment to restrict tripping and other noisy drilling operations to daylight hours and to control dust during the drilling phase. With respect to the interveners' concerns for the potential for drilling fluids to enter the local groundwater and domestic water systems, the Board accepts that, although unlikely, improperly controlled run-off from the lease could affect these water supplies. Therefore, if the application is granted, the Board would require that Pointer contain all drilling fluids in tanks and utilize a remote sump approved by the ERCB, unless agreement from the interveners can be obtained for on-site disposal.

The Board notes that the interveners agreed with Pointer's calculated H_2S release rate. The Board also agrees with this rate and the calculated planning radius of 108 m. The Board also notes that while the planning radius does intersect the County road, residents in the subdivision could, in the event of an emergency, leave by way of the U-shaped drive. Therefore, the Board does not believe that a full emergency response plan is required. However, considering the sensitivity of the area, and the number of residents, the Board believes it would be prudent to have a "preparedness" plan in place. If the application is granted, the Board would require Pointer to provide it with an emergency "preparedness" plan prior to spudding the well.

The Board believes that the measures proposed by Pointer would ensure that impacts are kept to a minimum while drilling the proposed well and, given the temporary nature of these impacts, should not preclude the drilling of the well.

With regard to impacts associated with producing the well, the Board believes that Pointer's proposal to pipeline the well immediately after drilling, thus eliminating tankage, flaring, and trucking, would reduce any related impacts to an acceptable level. The Board accepts Pointer's commitment to disguise the wellhead and any future pump with a small unobtrusive structure. The Board also accepts Pointer's commitment to utilize an electrically driven low profile screw pump when one is required. The Board finds that these measures go beyond many similar situations in the Province where oil and gas operations coexist with residential development. The Board does not believe that setting the wellhead below ground, given the associated safety risks, is appropriate.

With regard to drilling the 4-8 well from a 5-8 surface location, the Board is unconvinced that the very small potential for reduction in impacts would be sufficient to warrant the increased costs. In particular, the Board is concerned that the 5-8 location would simply transfer impacts to other residents. For example, while Mrs. Wilson, the owner of Lot 12, has apparently agreed to a well at 5-8, other nearby residents may not. Furthermore, the proposal by the interveners that Pointer use a pump jack rather than a screw pump at 5-8 in order to reduce the operating costs would potentially further increase impacts on those residents. The Board is of the view that drilling and servicing a well at the 5-8 location would only marginally reduce the noise for residents at the south end of the subdivision, while resulting in marginally more noise at the north end of the subdivision.

The Board believes that Pointer's estimate of $65 620 in additional costs for a successful well drilled from 5-8 may be high. On the other hand, the interveners' estimate of $45 000 did not take into account certain additional costs such as logging, testing, surveying, water, mud, engineering, etc. As a result, the Board views these estimates as being similar. The Board also notes that increased servicing would be necessary for a directional well, further adding to the cost of the 5-8 location once the well required a pump. The increased drilling and operating costs could have an effect on the producing life of the well and, therefore, on the conservation of the oil resource. The increase in drilling and operating costs associated with a directional well from 5-8, and the potential for reduced recovery of the oil resource, are not warranted by the marginal, if any, reduction in the impacts associated with drilling and operating a vertical well at 4-8.

For similar reasons, the Board does not consider the 1-7 location to be a viable alternative.

5 ALTERNATIVE OIL TARGET AREAS AND FUTURE OIL WELL SPACING

5.1 Views of the Applicant

A proposal was put forth by the interveners at the hearing that Pointer could apply to the ERCB for 32-hectare oil well spacing, with the target areas being Lsds 3 and 5 of section 8 (the 3 and 5 target areas) as opposed to 4-8 and 6-8. Pointer stated that its proposed mitigative measures would reduce impacts at the proposed well to an acceptable level and that a 3 and 5 target area pattern is unnecessary. Furthermore, the Lsd 3 target area would have to be directionally drilled because there are several residences on Lsd 3. It did indicate, however, that if the ERCB determined that a 3 and 5 target area is appropriate, it would comply with the ERCB's decision.

5.2 Views of the Interveners

The interveners proposed a change from the established 32-hectare oil target areas in the area to allow Pointer to relocate the proposed well. They suggested that the 3 and 5 target area pattern would allow Pointer to drill the Lsd 5 target from the 5-8 surface location, thus eliminating the need for the proposed well location. The interveners believed that the 5-8 surface location would provide an optimal location for drilling additional wells. They suggested that Pointer could access the Lsd 3 target area from the 5-8 location and, if in the future the oil well spacing were reduced to 16 hectares, Lsds 4 and 6 could also be drilled from the 5-8 location.

5.3 Views of the Board

In considering applications for changes to oil well spacing in the province, the Board must consider conservation of the resource, potential surface impacts, potential affected parties, and the need for a change in spacing. If an application were before the Board for 32-hectare spacing on the SW 1/4 Sec 8, with the target areas being Lsds 3 and 5, the Board would have a concern for the conservation of potential reserves that may underlie Lsd 4 of 8 and Lsd 1 of 7. The Board would also require the applicant to demonstrate that the change would not adversely affect the environment or other parties that may have an interest in the land surface. The Board believes that the proposal for Lsds 3 and 5 target areas, while addressing the concerns of the interveners, may also create greater impacts on other residents within the subdivision. Therefore, the Board does not consider the proposal for Lsds 3 and 5 target areas to be a viable alternative to Pointer's proposal.

6 DECISION

The Board has carefully considered the application made by Pointer as well as the concerns of the interveners. The Board believes there is a need for the well and is prepared to approve the well licence application subject to the following:

- Pointer shall submit an emergency "preparedness" plan to the ERCB prior to spudding the well.

- Pointer shall, unless consent can otherwise be obtained from the interveners, contain all drilling fluids in tanks and utilize a remote sump that has been approved by the ERCB Medicine Hat field office.

- Pointer shall comply with all commitments made in its application and at the hearing.

The Board approves Application No. 910227 and a well licence will be issued in due course.

DATED at Calgary, Alberta, on 30 April 1991.

ENERGY RESOURCES CONSERVATION BOARD

Bruce F. Bietz

B. F. Bietz, Ph.D.
Board Member

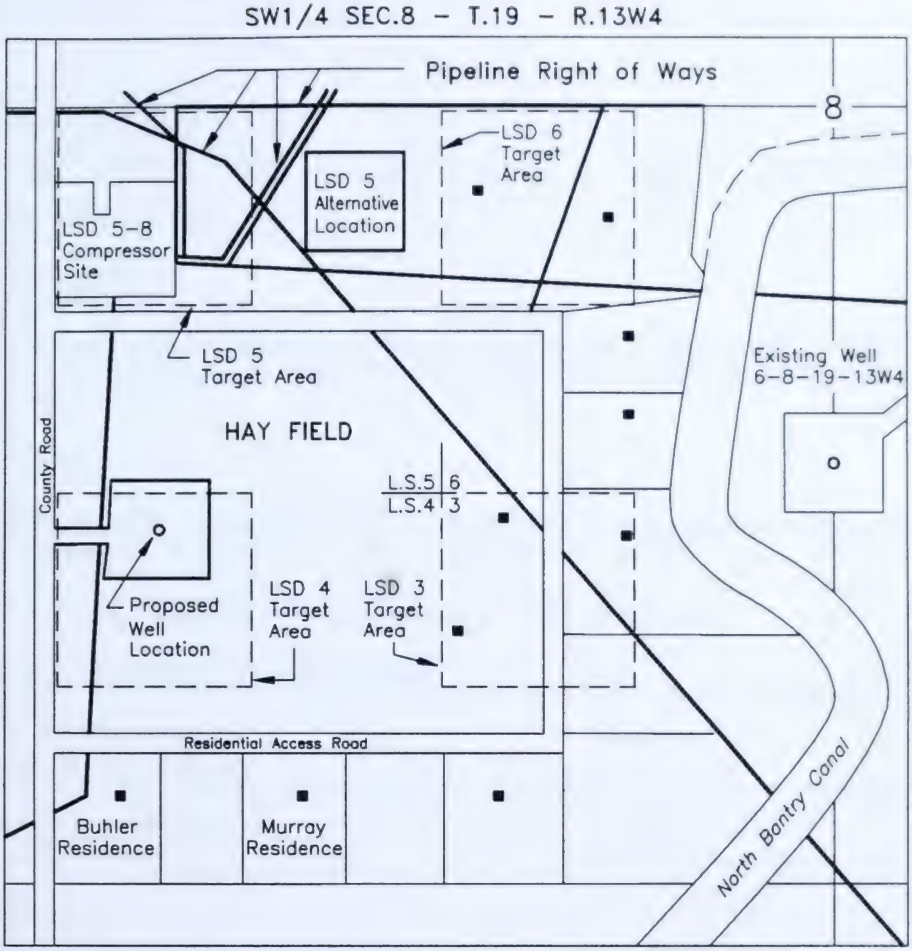
T. Homeniuk

T. F. Homeniuk, P.Eng.
Acting Board Member

* N. G. Berndtsson, P.Eng.
Acting Board Member

---

* Mr. Berndtsson was unavailable for signature but concurs with the contents and with the issuing of this report.



PROPOSED WELL LOCATION

Application No. 910227

Pointer et al Bantry 4-8-19-13W4

D91-3

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

MANALTA COAL LTD.
TO MODIFY THE BASE PLAN
COAL MINING SCHEDULE OF VESTA MINE

Decision D 91-5
Application 910459

1 INTRODUCTION

1.1 Application

Manalta Coal Ltd. (Manalta) applied to modify the Base Plan coal mining schedule of Vesta Mine No. 1046/01, pursuant to clause 4 of Licence No. C 85-10, to ensure the spoil pile stability and minimize coal losses.

1.2 Hearing

A public hearing of the application was held on 23 April 1991 in Calgary before a division of the Board comprised of F. J. Mink, P.Eng., M. J. Bruni, and J. W. Newton.

A list of those who appeared at the hearing is given in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Manalta Coal Ltd. (Manalta) A. L. McLarty	P. J. Scott, P.Eng. G. N. Hodges, P.Eng.
The Haeberles B. L. Anderson	M. J. Haeberle
Alberta Power Limited (APL) N. E. Romanow	
Energy Resources Conservation Board staff C.J.C. Page K. Jamil, P.Eng. E. S. Mahadeo, P.Eng. H. Knox, P.Eng.	

Chinook Management Ltd. (Chinook) objected to the application but did not appear at the hearing.

2 BACKGROUND

In 1988 Manalta applied to the Energy Resources Conservation Board (Board) for an order requiring Chinook, the licensee of the gas well, CHINOOK RED WILLOW 6-13-40-16 (6-13 well), to abandon the well to facilitate mining of coal at the well site in accordance with the Base Plan approved by Licence No. C 85-10. Subsequently Chinook applied for a permit to construct a pipeline to tie in the 6-13 well to the Newalta Red Willow Gas Plant. After a joint public hearing of both applications, the Board, in Decision D 88-14, issued in November 1988, granted Chinook's pipeline application for immediate tie-in and production. The Board also determined that to avoid a prolonged delay or interruption of Manalta's operations, the 6-13 well was to be temporarily abandoned or suspended on or about 1 July 1990 to allow mining to proceed and to permit Chinook to re-enter the well on or about 1 January 1993 to resume gas production. In addition, the Board established an operating committee, the Manalta/Chinook Committee (Committee), to be chaired by a Board representative, to resolve concerns regarding safety and scheduling difficulties.

In February 1989 Chinook withdrew its pipeline application because it was unable to obtain an acceptable gas processing arrangement. In April 1989 Manalta requested the Committee to advance the 6-13 well temporary abandonment date because of its accelerated mining schedule. Chinook did not support nor object to Manalta's request but indicated that it was unlikely that the 6-13 well would be placed on production prior to 1 July 1990. The Committee recommended the date be advanced to accommodate Manalta's schedule and to give Chinook earlier future access to the well site. Under this arrangement it was anticipated that Chinook would be permitted to re-enter the 6-13 well on or about 1 January 1992. The Board accepted the Committee's recommendation and the 6-13 well was suspended in October 1989.

In September 1990 Vesta Mine experienced a major spoil pile failure resulting in substantial coal losses. In January 1991 Manalta submitted a geotechnical investigation report to the Committee Chairman and applied to the Board for approval of a modified Base Plan mining schedule to ensure the spoil pile stability and minimize coal losses. The change in the schedule would result in the well site being available to Chinook in the first quarter of 1993 instead of the first quarter of 1992, which would have been possible with the accelerated mining schedule. On 15 March 1991, in response to a letter inviting objections from the Committee Chairman, Chinook filed a written objection to the Manalta application stating its desire to re-establish its well within the agreed time frame. Chinook added that the delay in Manalta's schedule would reduce its production window because of the planned mining operation in late 1995 in the adjacent Paintearth Mine, West Block area, of Luscar Ltd. (Luscar) which would interfere with its proposed pipeline to tie in the 6-13 well.

3 POSITION OF THE PARTIES

3.1 Manalta

In its opening statement at the hearing, Manalta, the operator of the Vesta Mine, made minor amendments to its application to modify the Base Plan mining schedule. The amendment would result in the well site being available to Chinook in January 1993 instead of first quarter 1993.

Manalta stated that its acceleration of mining operations led to the hope that the 6-13 well site would be available 1 year earlier. That expectation almost materialized if it had not been for the geotechnical problem of spoil pile failures which resulted in coal loss and increased operating costs.

The net effect, however, is that even with the spoil pile failure problem, the well site would be available in January 1993, precisely the date envisaged in 1988 (Decision D 88-14). Manalta also filed a letter from Luscar regarding the timing of its proposed mining operation in the West Block of the Paintearth Mine. Luscar confirmed that pipeline operations in the area would not have to be disrupted until 1997, at least a year later than that originally anticipated. Manalta added that this change in Luscar's schedule would increase Chinook's production window beyond the level envisaged by the Committee in 1989.

3.2 The Haeberles

The Haeberles, who are freehold gas royalty owners in section 13-40-16 W4M, expressed an interest in seeing gas production proceed as soon as possible. The Haeberles submitted that the request to modify the mining schedule should be allowed only if it will not further delay the natural gas production.

3.3 APL

APL is the lessee of coal rights in section 13-40-16 W4M, and the holder of the surface rights subject to certain easements. APL expressed support for Manalta's position.

4 ISSUE

The Board considers the issue respecting this application to be the optimum resource recovery and its effect on the timing of access to the gas and coal resources.

5 RESOURCE RECOVERY AND THE TIMING OF ACCESS TO THE RESOURCES

Manalta stated that its application is based on the operational considerations of the mine where only the sequence of mining cuts would change, not the mine plan. Manalta believes there is no impact on the Chinook well as a result of approving the revised mining schedule. Manalta said that for some years Chinook has been suggesting that production of the 6-13 well is imminent. In 1985 Chinook was encouraged to produce and expedite the depletion of the resource prior to mining occurring in the area. That did not happen. In 1988 Chinook sought and obtained approval to produce the 6-13 well for 18 months prior to encroachment by mining, but nothing happened. Manalta contended there is no evidence at the hearing that there is anything likely to happen in any sort of a critical future time frame. Manalta noted that to produce the 6-13 well, the wellbore has to be re-established or the well has to be re-drilled. A decision to re-establish the well is required by May 1991 according to the Base Plan mining schedule and by November 1991 according to its proposed modified mining schedule. Manalta added that despite ample opportunity to do so, Chinook has given no indication of an existing gas market or where this sour gas would or could be processed and how and when the well could be connected. Manalta concluded that even if it were to take the risk of spoil pile failure and incur the potential cost (of about $125 000) and coal losses (of about 50 000 tonnes) to provide an earlier date by which this well could be accessed, there is no evidence it would provide any benefit to anybody.

The Haeberles said that there are two competing natural resources, coal and natural gas, and any time the Board makes a decision it affects both natural resource productions and registered resource owners. The Haeberles noted that the change in mining schedule would result in a 1-year delay in the ability to produce natural gas and expressed an interest in seeing the natural gas production proceed soon.

The Board recognizes the current geotechnical problem and its impact on the mining schedule and coal recovery. Although the proposed modification to the Base Plan schedule would eliminate the 1-year advantage gained by acceleration of mining operations, the Board has no evidence to suggest Chinook is in a position to produce and market the gas. The Board also believes that the delay would not reduce Chinook's operating window because of similar change in Luscar's schedule. In addition, the Board is satisfied that the well site would be available to Chinook in January 1993, the date envisaged in the 1988 decision.

On the question of Chinook's intention to re-establish the 6-13 well, the Board notes that approving the modified mining schedule will postpone the date at which a decision is required from May 1991 to November 1991. The Board expects Chinook to discuss this issue with the Committee.

6 DECISION

Having considered the evidence, the Board has decided to grant Manalta Coal Ltd.'s Application 910459, as a significant modification to the mining plan, pursuant to clause 4 of Licence No. C 85-10.

DATED at Calgary, Alberta, on 31 May 1991.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

M. J. Bruni
Acting Board Member

JWNewton

J. W. Newton
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION FOR A WELL LICENCE
OKOTOKS FIELD
CANADIAN OCCIDENTAL PETROLEUM LTD.

Memorandum of Decision
Pre-hearing Meeting
Application 910253

1 INTRODUCTION

On 27 August 1990 Canadian Occidental Petroleum Ltd. (Canadian Occidental) made application to the Energy Resources Conservation Board (the Board) for a licence for a well to be drilled from a surface location in legal subdivision 6 of section 18, township 22, range 28, west of the 4th meridian. The well would be known as CDNOXY ET AL OKOTOKS 6-18-22-28 and would be for the purpose of obtaining production from the Wabamun Formation. The proposed well would be expected to encounter significant quantities of hydrogen sulphide (H_2S) gas. During the processing of the application by Board staff over several months, the Board became aware that several individuals and public interest groups had concerns respecting the proposed well and other wells planned for the area, and that a public hearing could be required to address the matters.

In order to afford all parties the opportunity to state their position on matters related to the application and the public hearing, the Board directed that a pre-hearing meeting be held. The meeting was held at the offices of the Board on 19 April 1991. Generally the following major topics were discussed:

1. the location of the hearing
2. the timing of the hearing
3. the scope of the hearing
4. funding for local interveners

The panel members presiding at the meeting were J. P. Prince, Ph.D., panel chairman, B F. Bietz, Ph.D., P.Biol., and R. G. Evans, P.Eng.

The names of participants who registered at the meeting are shown on the attached list.

2 VIEWS OF THE APPLICANT

Canadian Occidental submitted that as the well licence application had been pending before the Board since August of 1990, and since compensatory royalties were being paid to the Province of Alberta, the Board should establish an early hearing date. Canadian Occidental was of the opinion that a mid-June hearing date would be reasonable. However, to ensure that all parties had an opportunity to bring their concerns before the Board and that all information required to reach a decision was submitted, Canadian Occidental would not object to a hearing date in September 1991.

Canadian Occidental stated that the offices of the Board would be an appropriate location for the hearing.

Respecting the scope of the proceedings, Canadian Occidental stated that at this time only one application for one well licence was before the Board. It stated that it was its intention to file an application for an additional well to be drilled from the same surface location with a proposed bottom-hole location of 10-12-22-29W4M. These two applications should therefore be the subjects for consideration at any proceeding. Canadian Occidental submitted that it preferred to discuss intervener funding with parties in an informal setting but as guidelines for funding exist under Local Intervener Cost Regulations, it would be appropriate that all parties address their needs bearing in mind this legislation.

3 VIEWS OF THE INTERVENERS

The Over the Hill Community Group (Over the Hill) stated that it opposed the application and any such applications Canadian Occidental may submit to the Board. Over the Hill submitted that this was not an issue which should be decided solely by the Board. It suggested that it was appropriate that the Board deal with the technical merits of the application but the decision, if such drilling should occur at all, should be a political decision. Regardless of the scope of the proceedings, September of 1991 would be the earliest the group could be prepared. It agreed the hearing should take place at the offices of the Board.

Over the Hill submitted that because of the large number of issues involved, and because Canadian Occidental may wish to drill more wells than those applied for, it would be appropriate if the Board called an inquiry. The inquiry should encompass the question of drilling wells encountering H_2S along the eastern boundary of the city of Calgary and should entail such matters as safety, the environment, socio-economic factors, land constraints, restrictions and devaluation, and a wide range of community interests. It stated that the scope of the proceedings would be paramount in determining just what funding would be required or appropriate for it to seek.

The Castleridge/Falconridge Community Association (Castleridge/Falconridge) contended that the Board should postpone any hearings indefinitely. It was its position that no proceedings be held until such time as a definite H_2S policy and emergency response plan was developed by the City of Calgary (the City). Castleridge/Falconridge did not believe that communities in close proximity to H_2S facilities were adequately prepared in the event of an accident. It stated it would request funding so that a proper assessment of these matters could be made for the community.

Burnco Rock Products (Burnco) stated that it neither supported nor opposed the application. Burnco did request that sufficient time be allowed to review any submissions and for information requests and exchanges.

Carma Developers Ltd. (Carma) requested that sufficient information be tabled and sufficient time for assessment be allowed for it to determine what ramifications could result from approval of any applications. Carma submitted that planning impacts had to be determined and that time constraints in relation to any development or well use must be established and enunciated. Assimilation of the proper studies and information, and preparation for submissions to the Board, would dictate that proceedings should be held in the fall.

Ollerenshaw Ranch Management (Ollerenshaw) supported the position that a hearing should not be held before the fall. This would allow time for the appropriate consultants to be retained, information compiled, and submissions prepared for filing with the Board. Ollerenshaw also supported the Board offices as an appropriate venue.

The Calgary Board of Health (Board of Health) requested that 6 months be made available for assessment of its position, allowing for a hearing date in October. The Board of Health submitted that time was required to evaluate the scope of the existing and proposed development in relation to health studies, gas dispersal modelling, and exploration of mitigative measures.

The City neither supported nor opposed the application at this time. The City believed study was required to examine the potential for immediate and long-term impacts on land within city boundaries and possible implications for future expansion. In addition, time was required to review the applications and supporting information. Given this, the City supported a fall hearing to be held at the offices of the Board.

The Bow North Surface Rights Association Chestermere Area (Chestermere) submitted that the Board should hold an inquiry, if that was deemed necessary. If not, then a single hearing should be held considering both sets of applications, those being the two well applications in the Okotoks area and also two Canadian Occidental well applications in the Crossfield Pool area which had been pending before the Board awaiting completion of the GASCON 2 study. Chestermere said this would result in a saving of time and costs, and would avoid duplication of effort for all parties. It also submitted that a hearing date before the summer would be unrealistic.

Mr. Al Sidorsky (Mr. Sidorsky) raised the issues of notification and safety. He requested that some vehicle be established to inform the public of H_2S leaks and odour incidents so that a common database could be collected and used for health studies.

The Canadian Green Party supported the position of the other groups as to health and safety and requested an inquiry into the possible repercussions of any accident that may occur.

Alberta Greens supported the position that an inquiry be held on the development of H_2S gas in close proximity to the city.

Mr. Bill Hetherington submitted that the application should meet all Board requirements before it was given consideration. He contended that the area was having numerous H_2S-related problems and there should be accountability for it.

Mr. Nigel Lakey (Mr. Lakey) stated that at present he neither supported nor opposed the application. He did request, however, that all relevant information such as emergency response plans and drilling and completion practices be submitted and a reasonable time allowed for review. Mr. Lakey stated that offices of the Board were appropriate for any hearings, and stressed the need for all parties to maintain correct address and phone numbers for information exchange, notification, and emergency response planning.

4 VIEWS OF THE BOARD

The pre-hearing meeting addressed a number of issues that will affect the nature and conduct of the hearing. These issues included scope, timing, location, and funding. A decision on the scope of the hearing was considered of primary importance, since that could affect subsequent decisions regarding timing, location, and funding.

The current situation, with regard to sour gas development east of Calgary, as set out in the attached figure, is based on publicly available information. Four distinct gas pool boundaries have been established by the Board from information available to date, two of which bear particular relevance to the matters at hand. The Crossfield Wabamun A Pool (Board Order G 6744) trends in a north-south direction and extends to the south as far as 50 Avenue S.E. Sour gas produced in the pool is pipelined north and processed in the Petrogas plant. The Okotoks Wabamun B Pool (Board Order G 4638B) lies south of the Crossfield Pool and also trends in a north-south direction, ending at about Highway 22X to the north. Sour gas production from this pool is pipelined south and processed at the Mazeppa Gas Plant. These two pools, which were discovered in the early 1950s, currently contain approximately 60 producing wells. A parcel of land centring on the hamlet of Shepard and approximately 11 km wide has not been included by the ERCB within either pool because of insufficient information.

In assessing the appropriate scope for the proposed hearing, while recognizing a commonality of concern regarding sour gas development in general, the Board noted the divergence of participants' interests with respect to the specific wells proposed in the application. Stated broadly, two distinct proposals emerged from the meeting: one, a general inquiry into sour gas development in east Calgary, as suggested by several participants; the other, a hearing that would focus only on the two wells identified in Application 910253, as suggested by Canadian Occidental.

A general inquiry regarding Canadian Occidental's plans for development in east Calgary appeared to have some advantages, relating in particular to savings of time in future hearings and combining of interventions and witnesses—although, given the apparent divergence of interests, this latter advantage would by no means be certain. There are several disadvantages the Board believes should also be considered. The interests represented at the meeting fall into two broad groups: those whose primary concern is the two currently proposed wells, with their associated effect on land use and value, in the applications presently before the Board; and those whose concerns are more general, relating to sour gas development near densely populated areas, with the associated issues of safety, capacity for emergency response, and other communal interests. The Board did not view this division of interests as definitive—both groups hold in common many of the concerns raised at the meeting. However, a clear difference exists in the ranking of issues associated with sour gas development in the southeast, with its relatively low population density, and development in the northeast, which currently abuts directly onto the city limits. The Board recognizes some danger of inappropriate emphasis on one or the other set of concerns if they are grouped together in a single forum.

The Board also considered that one of the usual arguments favouring a general inquiry, the likelihood of said inquiry providing new information to the Board, was not compelling in the present instance. The Board would not get significantly more information from a general inquiry than it already has or could obtain through appropriately structured individual hearings. Moreover, the Board agrees with

Canadian Occidental's position that in these circumstances, forcing it to consider openly its plans for regions it did not yet have rights to develop would be unfair.

For these reasons the Board is of the view that a general inquiry dealing with development east of Calgary may not be the most desirable option.

In considering the proposal of Canadian Occidental that the hearing should focus only on the two proposed wells, the Board was cognizant of the degree of uncertainty for local residents inherent in such an approach. Whether the application was approved or not, residents would not know what further applications might be made or what alternative plans for development could emerge for the region in which they live. The Board, as well, would face uncertainties regarding the nature of likely future developmental activity.

The Board judged the uncertainties resulting from looking at only two wells in a large, somewhat defined pool as highly undesirable. The Board was reluctant to consider two wells in isolation, without benefit of some knowledge of the overall plans for pool development. Therefore, the Board sought an alternative approach that would be fair, efficient, and feasible.

The wells proposed by Canadian Occidental—both the currently applied-for wells in the Okotoks Wabamun B Pool and the possible wells being considered in the Crossfield Wabamun A Pool—are development wells, unlikely to alter the existing pool boundaries. Thus, the Board is confident in considering the region as three separate areas: the northern area containing the Crossfield Pool, the central area with no defined pool and no proven reserves, and the southern area containing the Okotoks Pool. The northern area is adjacent to the city limits over much of its length and is, therefore, in close proximity to a large population. The southern area lies a considerable distance south of Calgary, with a population of much lower density (and consequently a different set of concerns associated with potential development). The central area has some characteristics of its northern and southern neighbours but as yet has seen no sour gas development.

The Board sees several advantages to dealing with the three areas separately, allowing full airing of issues specific to each without confusing issues of one with the other. Moreover, the Board is comfortable requesting Canadian Occidental to provide development plans for each of the areas it plans to drill, at the appropriate time, whereas it would be reluctant to require development plans for the entire east Calgary region now, since the company's strategy is not fully developed. The suggested approach would mean that the company would be asked to provide its plans for each of the areas at the time it applies to drill a well. The present application would obligate the company to provide its plan for the Okotoks Wabamun B Pool. A future application in the Crossfield Wabamun A Pool would require submission of a reasonably complete plan for that pool and, if the company should eventually decide to develop the central area, a plan for it would be required as well.

This approach will ensure that residents throughout each region will have an opportunity to speak to development in their neighbourhoods but will allow focused consideration of issues specific to each. The approach will also foster efficiency by precluding issues specific to one area from impinging on the assessment of another.

It is the Board's view that the best interests of all parties would be served by focusing the hearing for the 6-18 and 10-12 wells on issues specific to those wells and to the development of the Okotoks Pool.

This will allow the hearing to examine in detail those issues of particular concern to local residents and others who may be directly affected by the proposed wells. The Board will expect Canadian Occidental to be prepared to discuss its plans for the Okotoks Pool in as much detail as practical. The Board notes that Canadian Occidental has been discussing a variety of issues with local residents and would encourage a continuation of this process prior to the hearing. The scope of issues under consideration at the hearing will include public safety, environmental impacts, socio-economic impacts, land-use restrictions and possible devaluation, and production timing constraints as they relate to the Okotoks Wabamun B Pool and its immediate vicinity. All aspects of drilling and producing may be considered; however, the sour gas processing plants themselves will not.

With regard to issues of more direct concern to the residents of northeast Calgary, the Board anticipates dealing with these much more effectively through a future process specific to the anticipated wells on the western boundary of the Crossfield Pool. The Board will expect Canadian Occidental to file a development plan for the area of the Crossfield Pool concurrently with any new application. The Board will also request that Canadian Occidental, prior to filing an application for new wells in the Crossfield Pool, develop and fund an extensive application review process, in consultation with community leaders and other stakeholders, to examine the issues particular to the northeast area. The structure and the participants in the process will be decided in direct consultation with the ERCB. The review process will identify local issues, generate the data needed to assess those issues adequately and, wherever possible, resolve them in order that an eventual hearing, if one is needed, can be as focused and effective as possible. The Board is given to understand, based on a letter dated 14 May 1991, from Canadian Occidental (attached), that the company acknowledges the need to carry out such public consultation. Participation in this process would not reduce the right of any legitimate intervener to a public hearing.

Finally, the Board will expect any application for a new sour gas well or other development in the area between the boundaries of the two existing pools to be accompanied by a development plan for that area, including anticipated well development programs, pipelining, and processing requirements.

With regard to time, the Board believes a fall hearing for the proposed 6-18 and 10-12 well applications would be appropriate. The Board will hold a hearing on the dates of 1-3 October 1991. This should provide Canadian Occidental ample time for submission of the completed application, including a development plan for the area, and for final submissions from all interested parties.

With regard to location, the Board notes that all parties were in agreement with holding the hearing at the ERCB's Calgary offices. The hearings will be held in Govier Hall, in the Energy Resources Building, 640 - 5 Avenue S.W., Calgary, Alberta. A formal notice of submission dates, hearing dates, and location will be issued in the near future.

Finally, with regard to hearing costs, the Board will consider any application for local intervener status, either prior to or following the hearing. All potential participants are urged, however, to examine the hearing model proposed, and determine for themselves whether their concerns would likely be best addressed during a hearing into the 6-18 and 10-12 wells, and development in the Okotoks Pool, or would be better held for the future application review process and possible hearings.

The Board has no objection if interested parties choose to deal directly with Canadian Occidental regarding intervener funding.

DATED at Calgary, Alberta, on 20 June 1991.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.*
Board Member

R G Evans

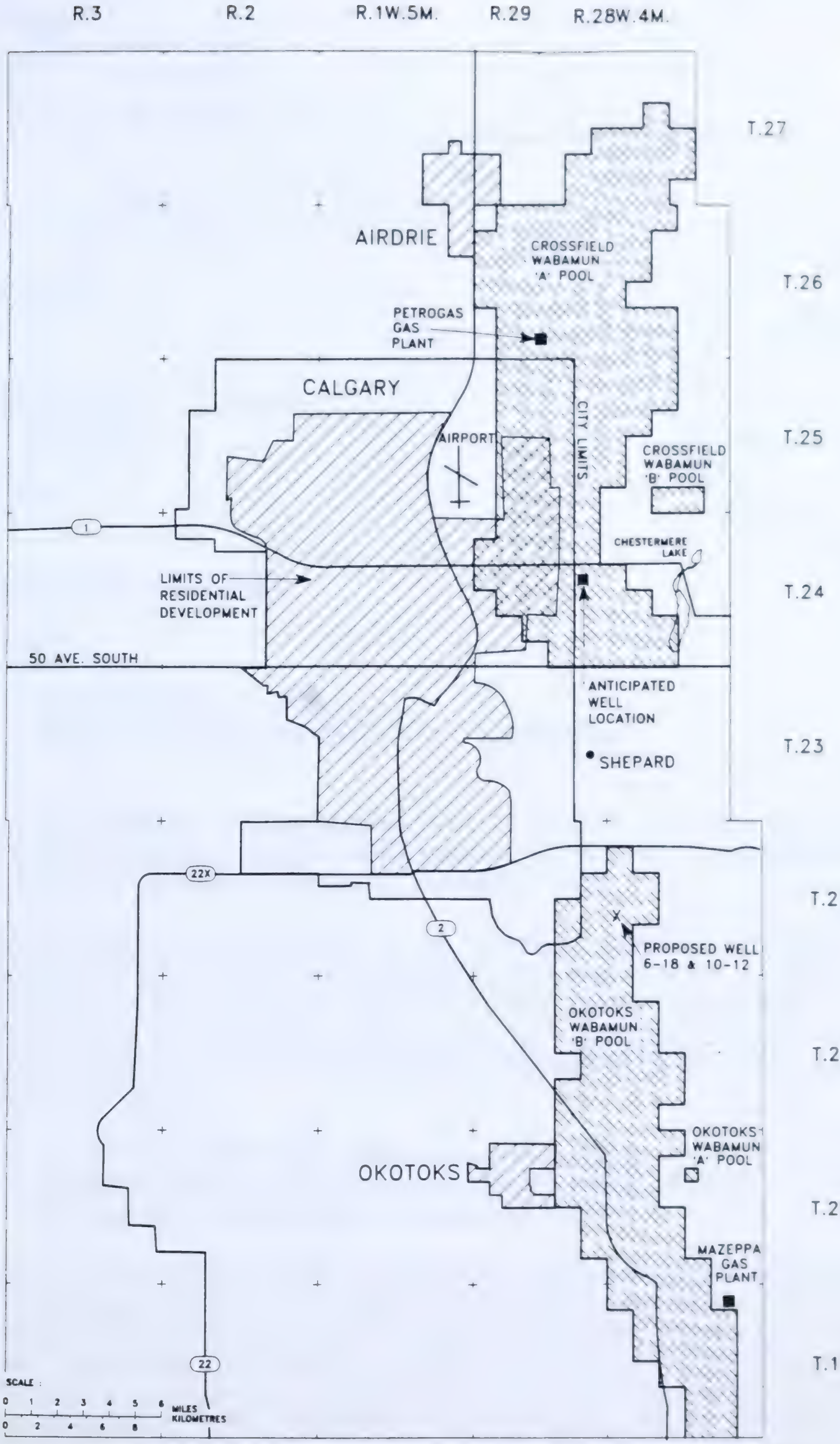
R. G. Evans, P.Eng.
Board Member

---

* Dr. Bietz was unavailable for signature but participated in the preparation and concurs with the issuing of this report.

PARTICIPANTS AT THE MEETING

Participants (Abbreviations Used in Report)	Representatives
Canadian Occidental Petroleum Ltd. (Canadian Occidental)	A. L. McLarty
Over the Hill Community Group (Over the Hill)	B. O'Ferrall R. A. Berrien
Castleridge/Falconridge Community Association (Castleridge/Falconridge)	A. Giga M. Langlois
Burnco Rock Products Limited (Burnco)	J. Snider
Carma Developers Limited (Carma)	J. Perraton
Ollerenshaw Ranch Management (Ollerenshaw)	D. Edie
Calgary Board of Health (Board of Health)	N. Carlson
The City of Calgary (the City)	T. Brown
Bow North Surface Rights Association Chestermere Area (Chestermere)	P. Edwards
A. Sidorsky (Mr. Sidorsky)	A. Sidorsky
B. Hetherington	B. Hetherington
Canadian Green Party	R. Fisher
Alberta Greens	P. Abranovitch
Nigel Lakey (Mr. Lakey)	N. Lakey
Energy Resources Conservation Board	Bob Heggie Nelson F. Lord



WABAMUN SOUR GAS DEVELOPMENT EAST OF THE CITY OF CALGARY

ERCB

cc. H. [illegible]

CANADIAN OXY
Canadian
Occidental
Petroleum Ltd.

1500, 635 - 8th Avenue South West
Calgary, Alberta, Canada T2P 3Z1
(403) 234-6700 Telex 038-21516
Fax (403) 263-8673

RECEIVED
MAY [illegible] 1991
BOARD [illegible]

May 14, 1991

Energy Resources Conservation Board
640 - 5 Avenue S.W.
Calgary, Alberta
T2P 3G4

Attention: Mr. Frank Mink

Dear Sir:

RE: **Public Consultation Process**
Proposed N.E. Calgary Well License Applications

Canadian Occidental, and its partners, wish to proceed with plans to drill additional development wells in the Calgary Crossfield Unit #1 to expedite the withdrawal of gas reserves on the city's urban fringe.

Given the history and sensitivity of this proposal, Canadian Occidental realizes that special consideration is required with respect to the proposed applications and as such has committed to a public consultation program in a recent letter to Community Associations, and appointed and elected government officials at the Municipal, City, Provincial, and Federal levels, the purpose of which is:

> "to permit CanadianOxy and key community leaders to jointly develop a detailed list of issues and affected groups, as well as to design a detailed public consultation plan."

There are several models of public consultation processes in the province that have had successful results, and Canadian Occidental would ask the Board's assistance in facilitating an effective public consultation process for this project. This would include active participation by Board staff in initiating the program and mediating issues identified, as well as support by the Board in establishing a realistic timeframe for consideration of the proposed applications so that the public consultation program can set its own critical path and work to a specific schedule.

Canadian Occidental is fully committed to participate in this type of forum with the affected stakeholders.

Sincerely,
CANADIAN OCCIDENTAL PETROLEUM LTD.

Ed Erlendson
General Manager, Engineering
Canadian Oil & Gas Division

EJE/sd
FILE: ED\ERCBMINK.LET

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY EDMONTON POWER
FOR THE COMMISSIONING SCHEDULE
OF GENESEE UNIT NO. 1

Memorandum of Decision
Application 910336
Planning Meeting

1 BACKGROUND

On 1 March 1991, The City of Edmonton (Edmonton Power or EP) submitted Application 910336 to the Energy Resources Conservation Board (ERCB or Board) respecting the commissioning schedule of the second unit of the Genesee Power Plant, Genesee 1. It requested that, instead of prescribing a date by which the unit should be made available to the Alberta Interconnected System (AIS), the ERCB should allow EP to determine, based on monitoring load growth on the AIS, when the unit should be completed.

The ERCB advertised the application for objections on 20 March 1991. A number of responses were received, several of which suggested that a public hearing should be scheduled to consider the application.

The ERCB scheduled a meeting on 22 May 1991 to hear further representations respecting this matter. Particularly, the ERCB wanted to discuss whether there is a need for a public hearing, or some alternative forum, to consider the application and, if so, what the scope and timing should be.

2 PARTICIPANTS IN THE MEETING

A meeting was held at the offices of the ERCB in Calgary. It was presided over by J. P. Prince, Ph.D., F. J. Mink, P.Eng., and R. G. Evans, P.Eng. Those who participated at the meeting are listed in the attached table.

3 POSITIONS OF PARTICIPANTS

Edmonton Power expressed the view that a hearing is not necessary to address the commissioning date of Genesee 1. It argued that extensive review and scrutiny of the Genesee Project has demonstrated that the unit is the next logical increment of generating capacity for the AIS. It submitted that another hearing would not provide the Board with further information on which to base a decision on the completion date. EP also stated that, given the uncertainties, determining a single date by which the unit would be required is not possible. It submitted that, using the current Electric Utility Planning Council (EUPC) working range forecast, the need for Genesee 1 varies from 1992 to 1998. Furthermore, a new EUPC forecast, which is expected to be issued this fall, would not be significantly different from the current forecast. Therefore, using the new forecast to assess the need for Genesee 1 would not provide any information that is not already known. EP stated that the status of contracts is not germane to the ERCB process and that the Public Utilities Board (PUB) would look into contracts as well as costs as part of its normal review process. Therefore, a hearing to review this matter is not necessary.

EP requested that the Board remove the "hold" on construction currently in effect for Genesee 1 and issue a permissive approval for the unit. It submitted that a permissive approval, i.e., an approval without a prescribed commissioning date, would provide it with the necessary flexibility to bring the unit on stream by the time the AIS needs generating capacity. To achieve this, EP would monitor the trend of actual electric load and would not resume construction until there is clear indication that the unit is needed to serve new electric load. If the trend of electric load growth warrants a re-start of construction, EP indicated that it would ask the Board for permission to resume construction, expecting that its request and the Board's decision would not be the subject of public hearings. EP further indicated that it is prepared to carry the commercial risks and defend its expenditures before the PUB upon completion of the unit.

EP indicated that 2 years of construction are required to finish Genesee 1. Therefore, once construction has been re-initiated, it would continue until the unit is completed. EP also submitted that, in the event that the unit were completed and load does not materialize sufficiently to justify its need, current regulatory treatment suggests that any operating benefits accrued through the displacement of more expensive generation would be used to offset the construction cost of the unit before it goes into the rate base, thus benefitting all consumers whose electricity rates are affected by the Electric Energy Marketing Act (EEMA).

EP indicated that an early September 1991 decision from the Board would allow EP to resume construction and make Genesee 1 available for the 1993 winter peak load.

TransAlta Utilities Corporation (TAU) submitted that granting permissive approvals would remove the only opportunity for other EEMA participants to review the need for additional generating capacity and the appropriateness of expenditures in advance of completion of the unit. Furthermore, it argued that a permissive approval would not allow the ERCB to fulfil its mandate for economic, orderly, and efficient development because it would leave the decision-making for timing of new capacity in the hands of one utility, while the ultimate cost would be shared by all EEMA participants. TAU contended that there is a need for a hearing or a technical conference and indicated that the issues to be dealt with would be: need for and timing of new capacity, the remaining expenditures (committed and non-committed) for the unit, the current status of construction, and the review of contracts and negotiations.

Alberta Power Limited (APL) stated that it is concerned only with the timing of Genesee 1. It stated that it believed the unit is the next logical increment in generating capacity for the AIS but that a hearing is required so that the ERCB and not Edmonton Power determines a commissioning date.

APL submitted that a permissive approval, with a 5-year window as alluded to in EP's application, would make it very difficult for other utilities to do any planning. It stated that there must be some timing limit put on the commissioning date; otherwise there cannot be orderly, efficient, and economic development. APL indicated that it expected that the outcome of a hearing would be an approval with a specific commissioning date or a short commissioning window.

W. Arsene supported TAU's and APL's positions and expressed the view that a hearing should be held.

The City of Calgary opposed a permissive approval. It argued that, with an open-ended approval, EP might lose control of costs. Therefore, a specific commissioning date is essential. It added that the Board should make a decision not only with respect to a commissioning date but also a date upon which construction should resume. The City of Calgary also submitted that an issue of concern is whether a broad-band forecast or some other type of forecast should be used to determine need.

The Building Trades Councils, The County of Leduc No. 25, CANA Limited, and Fording Coal Limited supported EP's application. In general, they submitted that Genesee 1 should be constructed as soon as possible to avoid cost increases and loss of job opportunities. Fording Coal Limited added that the prudence of expenditures associated with the unit is better dealt with by the PUB, after construction is completed and all costs are known.

IPCAA did not provide comment at the meeting. However, in its written response to the notice, it indicated that it is not opposed to the granting of a permissive approval, provided the approval reflected EP's acknowledgement that financial risks associated with such an approval rest with EP.

4 BOARD DECISION

The Board agrees that there are a number of matters raised by some of the participants at the meeting which could have an impact on the AIS and which require resolution before a completion schedule for Genesee 1 is approved. The Board has decided to schedule a public hearing to consider these issues and to hear representations from interested parties. The Board believes that the primary issues are the timing of completion of Genesee 1 and the cost implication of that decision on the AIS.

The Board expects to receive evidence and to hear arguments on the need for completion of the unit recognizing those factors which affect load growth in both the short and long term. Short-term examination could include recent load-growth patterns and any other factors deemed relevant.

Although the calculations of Load Carrying Capability which establish need for generating capacity are standard, there are a number of implicit assumptions that may differ among utilities. Therefore, the Board is of the view that these should be clearly identified in the submissions so that they can be properly addressed. Examples of these assumptions are: monthly peak loads, maintenance schedules, reliance on external ties, interruptible loads, potential self-generation, and amounts provided by small power producers.

The Board also expects to hear representations regarding the construction schedule to complete Genesee 1, as well as the associated costs. The Board is interested in total final costs, broken out by the following categories: expenditures to date, committed costs, uncommitted costs, and Allowance for Funds Used During Construction. These should be provided for a range of possible commissioning dates. Such a presentation should include a description of the existing contractual commitments for the plant and associated facilities and the cost implications inherent in completing the plant and mine for the options being considered.

The Board also believes that any cost-benefit analysis that EP may provide to justify the completion of Genesee 1 before it is needed, should meet the test of public scrutiny and should be part of the evidence at the hearing.

5 INFORMATION REQUIREMENTS

The Board expects Edmonton Power to provide information regarding forecasts of electric load that it considers most appropriate to determine Load Carrying Capability and the need for Genesee 1. It should also discuss the assumptions used as identified in the preceding section. In addition, for every year of need, Edmonton Power should provide the necessary construction schedules and costs associated with commissioning the unit.

The Board expects this information to be provided by Edmonton Power according to the process schedule shown below.

6 PROCESS SCHEDULE

Notice of Hearing	14 June 1991
Information from Edmonton Power	19 July 1991
Submissions	7 August 1991
Hearing	20 August 1991

DATED at Calgary, Alberta, on 5 June 1991.

J. P. Prince

J.P. Prince, Ph.D.
Co Chairman

F.J. Mink, P.Eng.
Co Chairman

R G Evans

R. G. Evans, P.Eng.
Board Member

PARTICIPANTS AT THE MEETING

Principals and Representatives (Abbreviations Used in Report)	Representatives
The City of Edmonton (Edmonton Power or EP)	D. Tadman A. Pettican, P.Eng. F. Shinyei, P.Eng.
TransAlta Utilities Corporation (TAU)	T. Dalgleish J. Tapics, P.Eng. D. Way, P.Eng.
Alberta Power Limited (APL)	M. Romanow B. Laing, P.Eng.
The City of Calgary	R. Goss G. Hanslip, P.Eng.
Industrial Power Consumers Association of Alberta (IPCAA)	D. Crowther
Fording Coal Limited	R. Thrasher R. Brander J. Popowich, P.Eng. D. Shyluk
Northern Alberta & N.W.T. (District of MacKenzie) Building & Construction Trades Council and Alberta and Northwest Territories (District of MacKenzie) Building and Construction Trades Council (The Building Trades Councils)	M. Hall
W. Arsene	W. Arsene
The County of Leduc No. 25	B. Sjolie
CANA Limited	M. Launer
Energy Resources Conservation Board staff	M. Asgar-Deen, P.Eng. J. Wilson, P.Eng. P. Wickel, P.Eng.

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATIONS BY THE IMPERIAL PIPELINE COMPANY, LIMITED/ ESSO RESOURCES (1989) LIMITED TO CHANGE SUBSTANCE IN THE EDMONTON TO SUNDRE PIPELINE FROM BLENDED BITUMEN TO NATURAL GAS AND FOR ASSOCIATED PIPELINE FACILITIES AND CONNECTIONS

Decision D 91-6
Applications No. 910114,
910115, 910116, and 910505

APPLICATION BY NORTHWESTERN UTILITIES LIMITED TO RECONSIDER APPROVAL OF FEDERATED PIPE LINES LIMITED NATURAL GAS LIQUIDS PIPELINE

Application No. 910357

SEP 11 1991

1 INTRODUCTION

1.1 Applications

The following applications were submitted:

Application No. 910114

An application by The Imperial Pipeline Company, Limited (Imperial) for a permit to construct approximately 0.80 kilometres (km) of 168.3-millimetre (mm) outside diameter (OD) pipeline to connect the Edmonton to Sundre Expansion Pipeline (ESEP) to an existing pipeline in the Bonnie Glen area.

Application No. 910115

An application by Esso Resources (1989) Limited (Esso) to discontinue the use of an approximately 9.5-km portion of its existing 168.3-mm OD ethane pipeline in the Bonnie Glen area, Licence No. 21001.

Application No. 910116

An application by Imperial to amend Licence No. 21719 to convert an approximately 95-km portion of the 323.9-mm OD ESEP between Ellerslie and Homeglen from crude oil to natural gas service; to convert an approximately 0.03-km crude oil pipeline, Licence No. 15440, to natural gas service in the Ellerslie area; to convert an approximately 9.9-km portion of existing Esso ethane pipeline, Licence No. 21001, to natural gas service in the Bonnie Glen area.

Application No. 910357

Northwestern Utilities Limited (NUL) applied under section 42 of the Energy Resources Conservation Act (the Act) to vary Board Decision D 90-8 with respect to Application No. 891483 by Federated Pipe Lines Limited (Federated) to transport natural gas liquids (NGL) to an existing Federated pipeline near the Esso Bonnie Glen gas plant.

Application No. 910505

An application by Imperial for a permit to construct a 3.3-MW (megawatt) compressor station and related facilities in legal subdivision 14 of section 11, township 49, range 25, west of the 4th meridian.

1.2 Hearing

The applications were considered at a Board hearing in Edmonton, Alberta, on 30 April 1991 and 1, 2 May 1991, with F. J. Mink, P.Eng. (Chairman), and Acting Board Members K. G. Sharp, P.Eng. and J. R. Nichol, P.Eng., sitting. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The Imperial Pipeline Company, Limited, Esso Resources (1989) Limited (Esso) D. G. Davies	R. D. Shields, P.Eng. C. D. Bird, P.Eng. C. K. Saunders, P.Eng.
Northwestern Utilities Limited (NUL) B. K. O'Ferrall J.E.E. Lowe	G. W. Welsh, P.Eng. L. D. Bruce, P.Eng. R. Armstrong, P.Eng. G. Engbloom, P.Eng. of Confer Consulting Ltd. T. H. Wise, P.Eng. D. J. Hawkins, Ph.D. both of Purvin & Gertz, Inc.
Federated Pipe Lines Limited (Federated) A. S. Hollingworth	
Shell Canada Limited (Shell) J. F. McGinnis	J. F. McGinnis
T. W. Morrison	T. W. Morrison
P. A. Young	P. A. Young
Conoco Inc. A. R. Ferguson	A. R. Ferguson
Energy Resources Conservation Board staff C.J.C. Page T. J. Pesta, P.Eng. P. Kahler P. K. Ferensowicz T. W. Dowsley, P.Eng. K. M. Johnston D. A. Peet, P.Eng.	

The following working interest owners in the Leduc-Woodbend D-3 A Pool (Leduc) submitted interventions in favour of the Esso applications, but did not appear at the hearing:
Toque Investments Ltd., North Canadian Oils Limited, Southern Cross Investments Ltd., Chevron

Canada Resources, Sereda Oils Ltd., NV Resources Corporation Ltd., Nevada Oil & Gas Ltd., Centipede Holdings Ltd., Norcen Energy Resources Limited.

Amoco Canada Petroleum Company Ltd., owner of Rangeland Pipe Line Co. Ltd., (Rangeland), submitted a letter stating that it did not oppose the ESEP conversion as long as transfers of oil from Rangeland to Esso's crude oil system, for transportation to Edmonton, were not affected.

2 PRELIMINARY MATTER, APPLICATION 910357

Before proceeding with the hearing on the Esso applications, the Board considered Application No. 910357 under section 42 of the Act.

2.1 Background

Federated's Application No. 891483 for a pipeline to transport natural gas liquids from a gas plant near Caroline to its pipeline near the Esso Bonnie Glen gas plant was heard at a public hearing to consider the recovery and processing of the Caroline Beaverhill Lake gas discovery. Board Decision D 90-8, issued on 31 August 1990, approved the Federated application as an integral part of that development, subject to receipt of the necessary approvals from the Minister of the Environment with respect to environmental matters.

2.2 Views of the Applicant

NUL, in its application, requested that the Board vary the decision it rendered on Application No. 891483 in Decision D 90-8, arguing that the availability of ESEP could obviate the need for a portion of Federated's NGL pipeline proposal. Additionally, it stated that because the Board requested information from Federated related to NUL's application and since Federated subsequently provided that information, the review of the previous decision had, in fact, started. It inferred that because of this action the Board had initiated the review.

2.3 Views of the Interveners

Federated argued that a review of Decision D 90-8 was not warranted, and requested that the NUL application be denied. Furthermore, Federated argued that its Application No. 891483 had been scrutinized intensely before approval was granted and that Federated should not be placed in a position where it would have to defend the merits of the project once again. It stressed that the vague allegations raised by NUL did not justify a review of a previous decision rendered by the Board. Esso and Shell supported Federated's intervention.

P. A. Young stated that she supports Federated's intervention. She noted that, in her opinion, the Board hearings were fair and the rulings well thought out. Thus it would not be appropriate to re-evaluate the decision.

T. A. Morrison pointed out that crude oil pipelines and NGL pipelines are designed and constructed to quite different standards and, therefore, to suggest that crude oil standards should be used for NGL service was totally irresponsible.

2.4 Views of the Board

The Board is satisfied that the matter to consider varying Decision D 90-8 was brought forward as a request by NUL. The Board noted that it considered the process of review to be a two-tier procedure. It found that consideration of arguments of whether or not to review would be the first step of that procedure. If the argument is compelling to suggest that new evidence may warrant a reconsideration, the actual review would be the second step.

The Board noted that the Federated pipeline application went through a complete, formal hearing process resulting in Decision D 90-8. Before the Board would review that decision, it expected NUL to satisfy the Board that circumstances have changed sufficiently to warrant a reconsideration of the decision. NUL argued that the ESEP may be a suitable alternative to the Federated proposal, although it did not show that there is a reasonable benefit to use the line for NGL service. The Board also notes that there was no interest by Federated or Esso in using the ESEP for NGL service.

Accordingly, NUL did not satisfy the Board that the Federated approval should be reviewed and the Board denied the request of Application No. 910357. No further consideration was given to the matter during the hearing.

3 ESSO APPLICATIONS NO. 910114, 910115, 910116, AND 910505

3.1 Background

Esso applied in 1985 to transport Cold Lake blended crude bitumen to Billings, Montana (Application No. 850350) through a pipeline connecting the Strathcona refinery in Edmonton with the Rangeland system at Sundre. The application was considered at a hearing and subsequently approved by the Board in Decision D 85-27. The pipeline was built and began operations in 1985. Esso is the owner and operator of the ESEP and has been the sole shipper on the pipeline during its entire operating life. Esso's applications are for the conversion of this pipeline to natural gas service.

3.2 Issues

In considering the applications, interventions, and evidence provided at the hearing, the Board believes that there are the following issues:

- need to accommodate excess Leduc gas
- need for the ESEP conversion
- transportation of blended crude bitumen
- economics
- other issues

4 NEED TO ACCOMMODATE EXCESS LEDUC GAS

4.1 Views of the Applicant

Esso is the operator of the Leduc gas cap blowdown conservation project which commenced in November 1989. Board Decision D 84-2 states that gas production from the pool must average a minimum of 3500 thousand cubic metres per day (10^3 m^3/d). NUL has a contract to purchase the gas production from the Leduc pool. Since the minimum blowdown rate exceeds NUL's current rate of take, excess volume must be stored for future delivery to NUL.

4.2 Views of the Interveners

None of the interveners questioned the need for the storage of Leduc gas in excess of the current sales to NUL.

4.3 Views of the Board

The Board is satisfied that all parties recognize the obligation of Esso to maintain gas production rates as described in Decision D 84-2. Given the rate of take by NUL it is also clear that some excess gas must be accommodated as a consequence of the blowdown.

5 NEED FOR ESEP CONVERSION

5.1 Views of the Applicant

Currently, the excess gas from the Leduc gas cap blowdown is stored in the Golden Spike D-3 A Pool (Golden Spike). Esso stated that the accumulating inventory of gas in Golden Spike is causing an increase in the reservoir pressure and that compression constraints will severely limit injection capabilities beyond 1992. Esso stated that approval of the ESEP conversion would allow for the excess gas to be redirected to other pools for use in miscible floods. These pools would include Esso's Wizard Lake D-3 A, Judy Creek BHL A and B, and several West Pembina Nisku enhanced oil recovery (EOR) schemes.

Esso stated that the ESEP conversion would also provide operational flexibility for inter-reservoir gas movements amongst its EOR schemes. The flexibility would allow Esso direct access to its own gas reserves, thus reducing the operating costs of its EOR schemes.

Esso indicated that approval of the ESEP conversion would also allow for an accelerated blowdown rate of 4000 x 10^3 m^3/d at Leduc resulting in incremental gas recovery of between 140 million cubic metres (10^6 m^3) and 280 x 10^6 m^3. This was determined by a reservoir simulation study. Esso stated that the variation in incremental recovery resulted from several different production scenarios being investigated; an incremental recovery of 240 x 10^6 m^3 appeared to be optimum based on production rates which could be accommodated by the ESEP conversion. Although Esso is committed to maintaining the minimum approved blowdown rate of 3500 x 10^3 m^3/d as required by Decision D 84-2 for as long as possible, it noted that its ability to do so in the later years of blowdown would be enhanced if the ESEP conversion is approved. Future gas production rates are expected to decline unless additional production wells are tied in.

Esso acknowledged there is a disagreement, currently before the courts, between itself and NUL over the interpretation of the terms of their gas purchase contract regarding the right to divert excess Leduc gas from the Golden Spike area. Esso stated that the viability of the ESEP conversion is not contingent upon the availability of the excess Leduc gas, noting that it would proceed with the conversion even if a court decision on the outstanding legal issue were not in its favour. Esso stated that it has significant volumes of established uphole reserves in the area and that these reserves alone would justify conversion of the ESEP. In addition, both the Wizard Lake D-3 A and Bonnie Glen D-3 A pools, which contain extremely large gas reserves, are scheduled for future blowdown and the gas from these blowdowns could be transported via the converted ESEP pipeline.

Esso stressed that it would continue to be the sole shipper on the ESEP; therefore there would be no impact on any third-party shippers. Furthermore, the ESEP conversion would benefit NUL since more gas would be deliverable as a result of higher recovery, and gas could be delivered through at least two systems to the Edmonton market.

Esso noted that the Golden Spike reservoir would be capable of handling the excess Leduc gas production resulting from a 3500 x 10^3 m^3/d blowdown rate if additional compression facilities were added. However, Esso believes that while the capital costs may be comparable, as discussed in Section 7 of this report, the ESEP conversion provides an attractive alternative to adding compression at Golden Spike. Esso also stated that the ESEP conversion would be cheaper to operate than the Golden Spike alternative, thus improving the economics of tying in existing shut-in wells for the Leduc blowdown.

Esso stated that the accelerated blowdown rate could be accommodated at Golden Spike only upon removal of the existing compression and pipeline constraints. Esso considered the removal of these constraints to be uneconomic, especially since the expanded facilities would be required for only a relatively short period of time.

Esso acknowledged that NUL could provide similar service to the ESEP for transporting Leduc gas. Since the NUL system is fully utilized, however, additional facilities would need to be added to accommodate Esso's requirements.

5.2 Views of the Interveners

NUL questioned the necessity of the ESEP conversion. NUL stated its belief that gas in excess of NUL's needs can continue to be stored in Golden Spike, as was originally intended. NUL questioned Esso's estimates of when and how much additional compression would be required at Golden Spike to accommodate the excess Leduc gas and still maintain the Board-approved minimum blowdown rates. NUL also noted that the original Leduc blowdown application anticipated that reservoir pressures would increase in the Golden Spike pool and that Esso expected capital expenditures would be required to increase compression capacity. NUL stated that in its view it remains economically viable to increase compression capacity at Golden Spike.

NUL noted that, with some modifications to its own system, it could provide the transportation service required by Esso, with the advantage of moving some gas by an exchange during winter when there are high gas demands in the Edmonton area. It suggested that the ESEP conversion could result in duplication of NUL facilities. It argued that with the ESEP conversion, gas could be flowing in the opposite direction to that on the NUL system, resulting in inefficiencies and duplication of facilities. It also argued that all public and private interest issues associated with the ESEP conversion can be physically accomplished through utilization of the NUL system, with the exception of the issue of tariffs. However, in NUL's opinion there were no serious discussions to resolve Esso's tariff concern.

NUL agreed that reserves recovery was a relevant issue to the Board's decision, but felt that Esso's determination of incremental recovery was less than the inherent error in such an estimate. NUL stated it would accept the Board's determination of the optimum blowdown rate from the Leduc pool and that it could transport or otherwise accommodate any increased volumes resulting from accelerated blowdown.

NUL stated that the purpose of the ESEP conversion was to remove Leduc gas from the Leduc-Golden Spike area and that there is an existing reserve dedicated contract which, in its opinion, does not permit such a transfer. It was NUL's contention that the contract stipulates that all Leduc gas not taken by NUL is to be stored in Golden Spike. In view of this unresolved contractual matter and since, in its opinion, there was insufficient evidence provided to support Esso's argument that the ESEP conversion is economically justified solely for the purpose of servicing other Esso gas reserves in the area, NUL contested the need for the ESEP conversion and requested denial of the applications.

5.3 Views of the Board

Although Esso stated that conversion of the ESEP is not contingent upon the availability of Leduc gas, the Board believes this to be the primary purpose for proceeding with a conversion at this time. Esso did not provide details of the proven and potential uphole gas reserves or associated production of this gas. Esso noted that the ESEP conversion could be employed for Wizard Lake D-3 A and Bonnie Glen D-3 A pool blowdowns; however, the evidence clearly indicates that blowdown at both of these pools is not expected to commence for several years.

The Board agrees with the applicant that the ESEP conversion would increase its flexibility with respect to the movements of proprietary gas. The Board believes that the ESEP conversion would provide Esso with several short- and long-term options which could result in cheaper gas production and transportation costs and, therefore, improved gas and oil recovery. In addition, the Board believes that Esso could more efficiently plan and design appropriate depletion for uphole gas and the Wizard Lake and Bonnie Glen D-3 A pools, if the ESEP conversion were to be operating at that time. This could result in a more orderly and efficient depletion of these reserves.

While the Board acknowledges that approval of the ESEP conversion could result in nominal inefficiencies in gas movements within the NUL and Esso systems for brief periods during the year, it does not consider these to be significant in this instance.

Because Leduc is underlain by an active aquifer, the Board accepts that higher recovery is a directionally correct result of a higher blowdown rate and finds Esso's estimate of incremental recovery to be reasonable. While the Board supports higher blowdown rates, it does not consider it necessary to increase the minimum withdrawal condition in the existing Leduc blowdown approval.

The Board notes that the production scenarios presented by Esso for both the ESEP conversion and the Golden Spike storage show withdrawals from Leduc declining below the 3500×10^3 m^3/d minimum rate for a significant portion of the blowdown period. Decision D 84-2 states that "a sustained rate of 3.5×10^6 m^3/d during the middle and late stages of depletion would provide for optimum gas-cap recovery". The Board still views this as an important consideration and expects that Esso will maintain the minimum withdrawal rate for as long as practically possible.

Several alternatives to handle the increased gas production from the Leduc pool were discussed. The Board believes that whatever alternative is adopted it should provide sufficient flexibility to allow for the highest possible Leduc blowdown rates to ensure optimum recovery from that pool.

The Golden Spike alternative resulted in conflicting evidence regarding the specific amount and timing of additional compression to accommodate the minimum blowdown rate. After reviewing the evidence, the Board believes that additional compression would be required to inject excess gas into

Golden Spike and is prepared to accept that the Esso position on the timing for such compression is representative.

The Board is satisfied that NUL facilities could provide alternative transportation service for the gas volumes described by Esso.

In summary, the Board believes that although the ESEP conversion, the increase in compressor capacity at Golden Spike, and the NUL alternative could all accommodate the excess Leduc gas on strictly a technical basis, and that the ESEP conversion and the NUL alternative could accommodate the transportation requirements of other gas, the ESEP conversion option would provide Esso with the greatest operating flexibility to manage its gas reserves and EOR schemes in this area. Furthermore, the Board does not consider the ESEP conversion to be a duplication of services, as suggested by NUL, because the NUL system cannot presently accommodate the transportation of the Esso gas without further modifications. Consequently the Board finds that, on a physical system basis alone, the ESEP conversion presents the best alternative.

6 TRANSPORTATION OF BLENDED CRUDE BITUMEN

6.1 Views of the Applicant

The ESEP was initially designed to transport 2700 m^3/d of blended crude bitumen and heavy crude oil (blend). Esso currently delivers approximately 1600 m^3/d to the Exxon refinery at Billings, Montana, under a short-term renewable contract since the market has not developed as expected.

The ESEP is operated by Esso as a common carrier; however, no serious interest has been expressed by other parties for transportation contracts and this has contributed to the underutilization of the pipeline. Esso acknowledged that there are seasonal variations in the blend demand and that it is not unreasonable for the pipeline to be occasionally idle since nominations for blend are often on a month-by-month basis. Esso stated that it has been the sole shipper on the ESEP; thus, converting the ESEP to natural gas service would have no effect on third-party shippers.

If the ESEP is removed from oil service, Esso stated that it could make alternative shipping arrangements for its blend through trade or by utilization of other existing pipelines. Esso is confident that with some relatively minor rearrangements to its existing pipelines, crude oil could move north and blend could move south, at foreseeable levels, with the transportation tariffs remaining at current levels or lower. Esso noted that it had recently carried out tests on a suspended 219.1-mm OD crude oil pipeline from Westerose to Edmonton and were confident that this pipeline could accommodate the foreseeable volumes of light crude oil from southern Alberta to Edmonton.

Esso agreed that a demand/supply projection for blend in Montana, produced by Purvin & Gertz, Inc. for NUL, is reasonable. Esso understood that a new coker at the Conoco refinery in Billings could constitute a potential new market for blend from the Cold Lake area, in the order of 6400 m^3/d. Exxon's Billings facility could also refine approximately 6400 m^3/d of blend. However, it stated that despite lengthy discussions with Conoco it had no contracts in place for any of these volumes and stressed that the need to transport blend to the Montana area over the next 5 years depends on the commercial attractiveness of the market.

6.2 Views of the Interveners

Conoco stated that it is installing a $150-million coker at its Billings, Montana, refinery. The coker will allow Conoco to process up to 8000 m^3/d of blend. Cold Lake blend is the preferred feedstock; however, there are other possible Canadian and American sources of supply if contracts cannot be concluded with the Cold Lake producers.

Conoco is concerned about its future access to blend supplies and the ability to move blend to the Montana market at a reasonably competitive transportation cost. It acknowledged that since negotiations are ongoing, the ultimate throughput requirements for the transportation system are not known. It requested Esso to commit to further development of a pipeline plan to allow movement of Cold Lake and other Edmonton-based blend to the Montana market; however, it did not expect Esso to invest in pipeline capacity prior to finalization of contracts. Conoco was somewhat satisfied that Esso has considered an alternative for transporting the blend to Montana that would not result in an increase in tariffs.

Purvin & Gertz, Inc. prepared a review of the blend market for NUL. The main conclusions of the report are:

- exports of Canadian heavy crude oil to Montana have grown since the installation of the ESEP in 1985;
- Montana is an important market for Canadian crude oil;
- the demand for blend should increase by the middle of 1992;
- the ESEP pipeline plays a vital role in delivering blend to the Montana market.

NUL indicated that even if Exxon were to discontinue purchasing Canadian blend, there could be a need for the ESEP to deliver Canadian blend to Conoco. If the ESEP were taken out of service, additional oil transportation facilities may be required to accommodate Conoco's expected requirements. NUL argued that there is no uncertainty in the Montana market for blend and that the applicant should demonstrate that the ESEP is no longer required for blend service.

6.3 Views of the Board

The Board is satisfied that present requirements for the ESEP to transport blend are limited. Even though the pipeline has been available to other shippers, Esso remains its sole user. Since the start of operation, even after considering seasonal variations, the average volumes have been well below the design flow rate, as well as lower than anticipated by Esso. Although some evidence was presented about the upside potential for markets in this area, the Board was presented with limited specific information with respect to volumes required or the timing for those requirements. Furthermore, all future volumes would be subject to the establishment of new contracts and there appeared to be alternative sources of supply which could preclude the need for the ESEP system. Should the increase in demand develop, and if the ESEP is not available at that time, the Board believes that Esso could accommodate the transportation of blend to the Montana market by rearranging its other pipelines. The Board notes Esso's statement that the costs of such rearrangements would not result in increased tariffs for crude oil or blend shippers and that Esso has committed to proceed with the rearrangements when justified by market conditions. Given the historic deliveries and the current level of underutilization, the Board is satisfied with Esso's position that the ESEP can be removed from blend transportation service without significant adverse effects on the provincial pipeline network for crude oil or blend transportation.

7 ECONOMICS

7.1 Views of the Applicant

Esso stated that the ESEP conversion would require an initial investment of $10 million which includes $235 000 for a tie-in of the ESEP line to an idle 168.3-mm OD Esso pipeline between the Alberta Ethane Gathering System and the Bonnie Glen gas plant. Esso expects the operating costs for the converted ESEP to be approximately $350 000 per year. Esso maintained that the alternative to the ESEP conversion would be to add compression at Golden Spike at a cost of $9.5 million. This expense would include $2.2 million for an additional power connection to Golden Spike from TransAlta. The operating costs for this alternative are estimated to be approximately $300 000 per year.

Esso favoured the ESEP conversion, citing many advantages over adding compression at Golden Spike, as discussed in Section 5. Esso stated that the ESEP conversion would be in service longer since it has a projected operating life of 20 years, versus a 2-to-3-year life for the additional compression at Golden Spike.

Esso noted that the ESEP conversion would provide increased opportunity for improved economics at its EOR schemes without any increase in royalty relief.

Esso stated that the expense of adding compression or looping pipelines between Golden Spike and the Edmonton Ethane Extraction Plant to achieve the same incremental recovery of gas as under the ESEP conversion proposal could not be justified by the present value of this gas, estimated to be $1 million. The cost of incremental compression and pipeline looping was only casually assessed by Esso but it estimated that pipeline looping would cost between $10 million and $15 million. While Esso admitted some incremental gas could be recovered under the Golden Spike scenario, there is little economic incentive to capture this because of the storage and processing costs that would be incurred on gas that would not be sold for 15 years.

In addition to the direct investment for the ESEP conversion, Esso also stated that approximately $3.5 million would have to be spent converting other oil pipelines to replace the oil service currently provided by the ESEP and other oil pipelines in the area. These costs could be recovered through normal tariffs.

Esso stated that in its view, three receipt/delivery contracts, subject to NUL's Rate 30 transportation rate, would be required if it were to utilize the NUL system. Based on this, Esso determined that the NUL tariffs, for the same services that the ESEP conversion could provide, would amount to $5.9 million per year. Esso agreed that NUL could provide similar pipeline service to that desired by Esso. However, mainly because of the NUL tariffs, it stated that the use of NUL facilities would not be an attractive alternative to the ESEP conversion.

7.2 Views of the Interveners

NUL stated that its facilities could provide the transportation service Esso requires for less than half the capital cost of the ESEP conversion. NUL estimated its proposal would cost $4.6 million with annual operating costs of $400 000. NUL also stated that the ESEP conversion is the more costly method of diverting and improving recovery of gas from the Leduc reserves. NUL pointed out that modifying Golden Spike is a higher cost alternative to using NUL facilities, but is less than the ESEP conversion. NUL added that, in its view, Golden Spike can accommodate some, if not all, of any incremental recovery from Leduc.

NUL estimated the annual cost of its service would be approximately $3.4 million under NUL's Rate 31 for short-term service. This would provide Esso with the same nominal capacity as the ESEP conversion, or 2800 x 10^3 m^3/d, and would provide service for yearly storage. The same service under the NUL Rate 30 for long-term firm service would cost approximately $2.9 million.

Esso's requirement for firm service on the NOVA system, or 1830 x 10^3 m^3/d, was estimated by NUL to cost approximately $2.7 million under Rate 31 and $2.4 million under Rate 30. NUL also stated that in order to be competitive, it is able to negotiate special transportation service rates, providing these do not negatively affect on other customers.

7.3 Views of the Board

The Board believes that the costs associated with using Golden Spike storage to maintain the minimum blowdown rate would not be prohibitive. However, the Board also believes that the ESEP conversion is more cost-effective and would facilitate accelerated blowdown. This is in spite of the fact that the Board does not accept Esso's argument that the added compression at Golden Spike would only be utilized for a 2-to-3-year period versus the projected operating life of 20 years for the ESEP. The Board believes that Golden Spike could provide long-term economic value as a peak load storage facility or, alternatively, the equipment could be redeployed elsewhere to extend its working life.

Although the ESEP conversion would require some $500 000 more in capital costs than the Golden Spike storage option, this additional investment could result in an estimated incremental recovery of 240 x 10^6 m^3 of gas which would be worth approximately $15 million (undiscounted). The Board estimates this gas would be worth approximately $2 million in present-value terms and believes the ESEP conversion would appear to be viable solely on the basis of recovery of these reserves.

The Board agrees with Esso that the additional investment that would be required for Golden Spike to achieve the same level of incremental recovery as the ESEP option would not be economic. The incremental gas that could be recovered would not justify compression investment or looping of pipelines to Golden Spike.

The Board recognizes that at least $3.5 million of additional capital investment could be required to permit the continued shipment of crude oil that would be affected by the ESEP conversion. Esso indicated its willingness to undertake such a project should commercial considerations so warrant, and noted that the conversion represents mainly a risk to Esso since it is the only shipper on the pipeline. The Board notes that despite the incremental investment, Esso believes that the tariffs for the delivery of third-party oil would be equal to or less than the existing tariffs.

The Board acknowledges that benefits could arise from the ESEP's ability to access other established and uphole gas reserves; however, it is difficult to verify the overall royalty implications to the Crown because of uncertainties in the timing of commercial development for these reserves.

NUL's proposal to provide the same service as Esso's ESEP conversion would require $4.6 million in capital costs. Compared to Esso's proposed capital cost of $10 million, this would represent savings of approximately $5.4 million, excluding oil pipeline costs. Although the Board recognizes that there would appear to be considerable savings in capital expenditure associated with the NUL proposal, it believes NUL's facilities would not be cost-effective given the tariff rates that would be incurred by Esso. The Board notes that the differences between the tariffs calculated by Esso and NUL arise from differences in the assumptions regarding receipt and delivery points to provide Esso's desired service. Notwithstanding these differences, it would appear that the NUL option is not cost-effective in the long term.

While it may have been useful to see more negotiation on the NUL tariff, the Board believes that NUL, having regard for its other customers, is unlikely to have sufficient flexibility to reduce the rate structure to be competitive with the ESEP conversion. Therefore, the Board believes that the ESEP conversion is the most economic long-term alternative.

8 OTHER ISSUES

8.1 Views of the Applicant

Esso agreed that security of supply of gas to Edmonton is a matter of public interest. It argued that Edmonton's security of supply would not be at risk by its proposal. Esso stated that, regardless of where the Leduc gas is stored, equivalent volumes of gas could be provided to NUL as required at several delivery points. It further argued that security of supply is dealt with by the ERCB through its removal permit policies and procedures, not in pipeline applications. It stressed that NUL has arranged for its security of supply through contracts.

In response to a suggestion that the Bonnie Glen ethane pipeline should remain in ethane service, Esso argued that the pipeline is presently idle. It has considered its options for further ethane sales and believes adequate alternatives exist to move its ethane to market.

Esso suggested that its applications would involve the modification of a privately owned pipeline which is used solely to transport the production of an affiliate company, and there should be no requirement for the Board to embark upon an examination of potential uses for the ESEP other than the one proposed by Esso. It noted that the owner should have the right to utilize its investments as it sees fit, subject to the Board's overriding assessment of the public interest. Esso stated that the choice of the ESEP conversion or a possible NUL option should be a purely commercial decision. Esso stressed that it would be spending its own money and that neither NUL nor the public of Alberta is being asked to pay, in any way, for the conversion. Thus, in Esso's opinion there are no public interest considerations that should preclude the approval of the Esso applications.

8.2 Views of the Interveners

NUL stressed that under deregulation the government has encouraged utilities to protect a supply of gas for Alberta customers by contract. It stated that security of supply to NUL and its customers is a public interest consideration and it does not believe that gas removal permit policies guarantee supply to NUL. NUL registered concern for its security of supply and security of deliverability should the Leduc gas be redirected from the Leduc/Golden Spike area. NUL also expressed concern that if the Board were to approve the ESEP conversion, the action could be interpreted as either overriding the contract between NUL and Esso or indicating that the contract should be overridden.

NUL stated that the future Bonnie Glen ethane delivery system is relevant to the public interest aspects of the ESEP applications. In the context of the public interest, NUL believes consideration should be given to the subsequent incremental capital costs related to replacing or restoring the ethane delivery capability currently in place at Bonnie Glen. NUL further provided evidence that Dow Canada's ethylene plant proposal in Fort Saskatchewan could be on stream in the second half of 1994 and that Dow has identified Bonnie Glen as a potential source of ethane. In NUL's view, Bonnie Glen would be one of the more attractive sources of ethane.

NUL stressed that its customers would benefit from reduced rates if it transports the gas for Esso since the average unit cost of transportation would be reduced with the increased volume. In NUL's opinion, this would be more efficient than removing an oil pipeline from service. All other things being equal, NUL stated that it should transport the gas because of the benefits to other users of its system; it argued that the ESEP conversion would not benefit other producers or other working interest owners. It stated that Esso is acting completely in self-interest and internal company interest while utilization of the NUL system would be in the public interest. It argued that Esso's private gain should be given less weight than the public benefits.

NUL stated that it is regulated by the Alberta Public Utilities Board which allows it to recover costs and to earn a reasonable rate of return on the equity component of its rate base. It does not have a monopoly on gas transmission, and requires ERCB approval to build a pipeline. NUL agreed that the same criteria for assessing pipeline applications should apply to it as to others. It also agreed that the ERCB should have regard for whether or not a pipeline might promote reserves development, enhance reserves recovery, provide opportunities to market gas, or result in better or more efficient use of pipeline capacity.

8.3 Views of the Board

While the Board acknowledges NUL's concern that the ESEP decision could have some effect on its contract with Esso, it is not in a position to judge what that impact is, or the commercial advantages to either party of the contract. The Board wishes to emphasize that it has not considered if, under the terms of the contract between NUL and Esso, Esso may divert gas. It believes that the question of whether or not there is a right to divert gas is purely a legal matter to be decided by the courts and not necessarily relevant to the disposition of the applications. Furthermore, Esso has indicated that it would proceed with the ESEP conversion regardless of the outcome of the court decision, as it could use the pipeline to transport other gas.

The Board agrees that security of supply and deliverability are important public interest issues; however, Esso has committed to the Board to return volumes of gas to NUL which would be equivalent to the excess gas produced from Leduc. The Board would expect that the undertaking would also provide some deliverability options to NUL. Therefore, the Board believes that the security of supply and of deliverability is not at risk. The Board agrees with NUL that the gas removal policies of Alberta are of little consequence to this decision.

The Board believes that the Bonnie Glen ethane line, which would be converted to gas service for ESEP, could be made available again for future ethane service at minimal cost or alternative ethane transportation methods could be arranged when necessary.

The Board acknowledges that the owner should have the right to utilize its facilities in a manner it thinks appropriate within the limitations of public interest. The Board is satisfied that from a public perspective the main issue is whether or not the NUL system should be utilized for the transportation of the gas rather than the ESEP conversion suggested by Esso. While the utilization of the NUL system by Esso could result in some benefits to the users of the NUL system, the Board would expect NUL to be competitive with other pipeline proposals in a deregulated market environment.

The Board thus believes that there is no overriding public interest issue to favour the NUL transportation alternative over the ESEP conversion.

9 CONCLUSION

The Board is satisfied there is a need to accommodate excess Leduc gas and that it would be in the public interest to provide an alternative transportation option for the surplus Leduc gas as described by Esso. Both the ESEP conversion project and the NUL transportation proposal could accommodate this need with similar public benefits, although the NUL alternative did not appear to be cost-effective. Furthermore, the Board is satisfied that the ESEP conversion would increase Esso's flexibility for utilizing its proprietary gas and could result in a more orderly and efficient depletion of oil and gas reserves. The Board is also satisfied that the ESEP can be removed from blend transportation service without serious adverse effects on blend or crude oil movements or tariffs on third parties. Therefore, after considering the issues, the Board concludes that the Esso pipeline proposal for the ESEP conversion project is acceptable.

10 DECISION

The Board approves Applications 910114, 910116, and 910505 by The Imperial Pipe Line Company, Limited and Application 910115 by Esso Resources (1989) Limited, subject to the receipt of approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act.

DATED at Calgary, Alberta, on 13 August 1991.

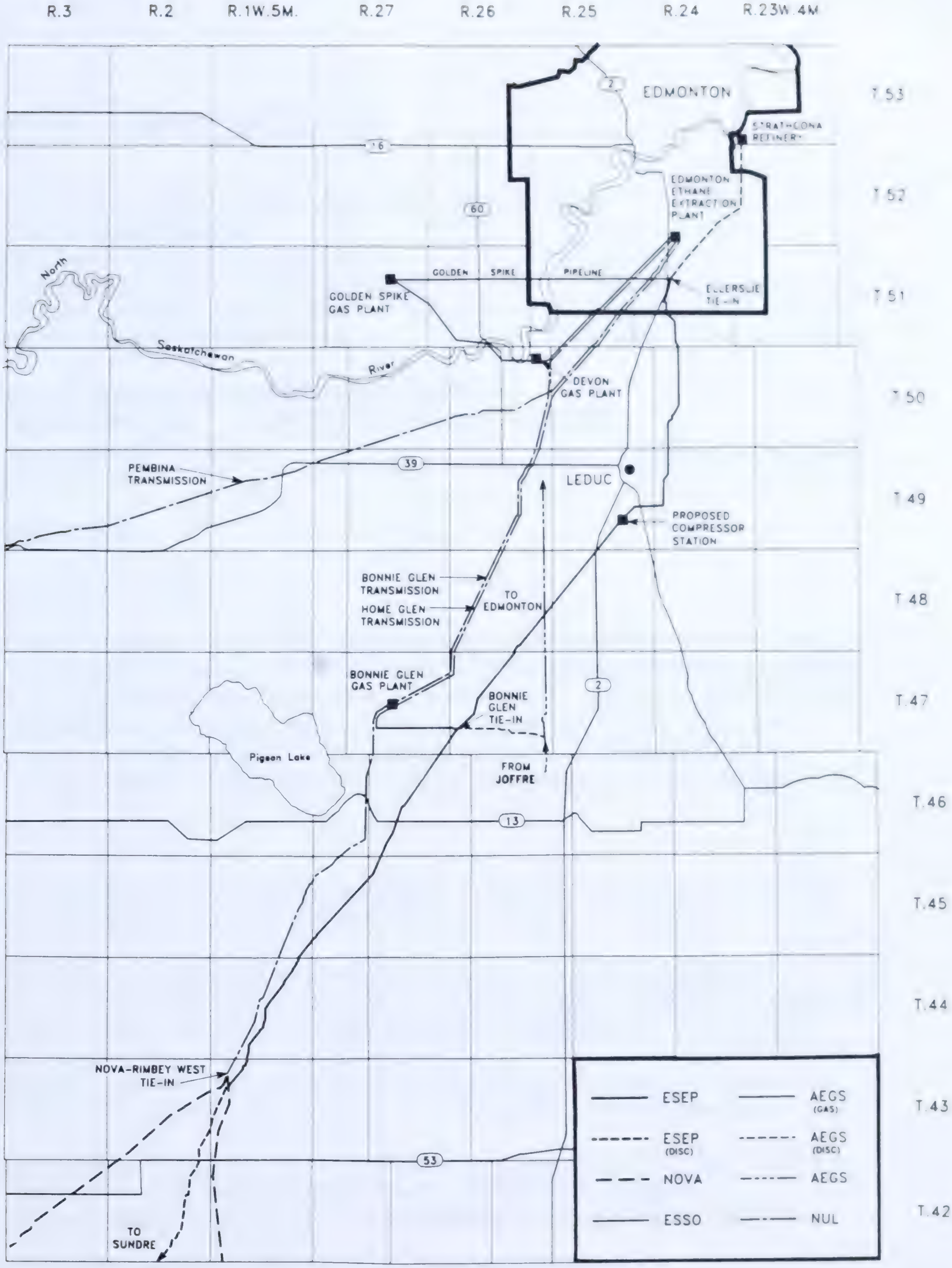
ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

K. G. Sharp, P.Eng.
Acting Board Member

JR Nichol

J. R. Nichol, P.Eng.
Acting Board Member



PROJECT AREA

Applications No. 910114, 910115, 910116, 910357 and 910505
The Imperial Pipeline Company, Limited/
Esso Resources (1989) Limited
Northwestern Utilities Limited

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY THE IMPERIAL PIPE LINE COMPANY LIMITED/
ESSO RESOURCES (1989) LIMITED
TO CHANGE SUBSTANCE IN THE EDMONTON
TO SUNDRE PIPELINE FROM BLENDED BITUMEN
TO NATURAL GAS AND FOR ASSOCIATED
PIPELINE FACILITIES AND CONNECTIONS

Addendum to Decision 91-6
Applications No. 910114,
910115, 910116, and 910505

APPLICATION BY NORTHWESTERN UTILITIES LIMITED
TO RECONSIDER APPROVAL OF FEDERATED PIPE LINES LIMITED
NATURAL GAS LIQUIDS PIPELINES

Application No. 910357

---

1 INTRODUCTION

1.1 Application No. 910505

The Imperial Pipe Line Company Limited (Imperial) submitted an application for a permit to construct a 3.3-megawatt compressor station and related facilities in legal subdivision 14 of section 11, township 49, range 25, west of the 4th meridian, as shown in the attached figure. Application 910505 was one of a number of applications submitted by Imperial, Esso Resources (1989) Limited (Esso), and Northwestern Utilities Limited respecting the conversion of the Edmonton to Sundre Expansion Pipeline from blended bitumen to natural gas service and the construction of associated facilities.

1.2 Hearing

A hearing was held in Edmonton, Alberta, commencing on 30 April 1991, to concurrently consider the applications respecting the Edmonton to Sundre Expansion Pipeline.

The Energy Resources Conservation Board issued Board Decision D 91-6 on 13 August 1991. Subsequent to the issuance of the decision report, the Board received further representations respecting Application 910505, dealing with location and effects of the proposed compressor station, from a Mr. Lust, who was not given proper notice of the original hearing. The Board decided to re-open the hearing to consider his concerns. The permit to construct the 3.3-megawatt compressor station was issued on 28 August 1991; however, the issuance of the related pipeline permits is pending.

The representations were considered at a Board hearing in Leduc, Alberta, on 4 February 1992, with F. J. Mink, P.Eng. (Chairman), and Acting Board Members K. G. Sharp, P.Eng. and J. R. Nichol, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

Subsequent to the hearing the Board visited the proposed compressor site.

2 LOCATION AND EFFECTS OF THE PROPOSED COMPRESSOR STATION

2.1 Views of the Applicant

Imperial stated that the proposed compressor station was an integral component of the conversion of the Edmonton to Sundre Expansion Pipeline to natural gas service that was subsequently approved by the Board in Decision D 91-6 and further stated that the onus was on Mr. Lust to show why the approval of the compressor station should be rescinded.

Imperial described its site selection process as outlined in a report prepared by Tera Environmental Consultants (Tera), and submitted as part of the original application. It identified a 5-kilometre (km) corridor, dictated by pipeline hydraulics and pipeline wall thickness, for locating the compressor station. Imperial concluded that moving the compressor station north of the 5-km corridor would require extensive pipeline replacements, resulting in greater environmental disturbance. Locating the compressor station south of the 5-km corridor would entail installing a compressor with multiple units needing greater power, resulting in greater impact on the surrounding area and local residents. Within the 5-km corridor, three potential sites were identified. The preferred site was selected by considering existing infrastructure and pipeline facilities, agricultural and environmental effects, and the effects on the nearest residents.

Minimizing the effects on agricultural practices and agricultural land was the primary consideration in selecting the preferred site. Other environmental effects were either similar between sites or could be readily mitigated. Imperial would implement the mitigative measures recommended in Tera's site selection report. In response to concerns raised by Mr. Lust, Imperial stated that normal lighting at the compressor station would be by shrouded low-intensity bulbs. High-intensity lighting would only be used in emergency situations and would be turned on by the operator.

The Noise Impact Statement prepared by HFP Acoustical Consultants Ltd. (HFP) indicated that the existing nighttime ambient sound level at Mr. Lust's residence is already higher than the expected sound level contribution by the proposed compressor station. Near Mr. Lust's residence, the sound level contribution by the proposed compressor station is predicted to be well within that allowed by the ERCB Noise Control Directive, even if it is assumed that aircraft flyovers are not a factor.

Imperial stated that residents within 1.5 km of the proposed compressor station were notified of the project prior to the original hearing. During the course of discussions and communication, Mr. Lust was the sole resident to object to Imperial's proposed compressor station. Subsequent correspondence and communications between Mr. Lust and Imperial failed to resolve Mr. Lust's concerns. Further contacts with all residents were attempted prior to the re-opening of the hearing.

In concluding, Esso stated that the proposed compressor station would meet the ERCB's Noise Control Directive. Imperial argued that it had undertaken a proper review process in determining the site for the proposed compressor station and that mitigative measures would be taken to further reduce the impact of the compressor station. Esso would perform another baseline noise study in the fall and a post-construction noise study would be conducted to ensure that the actual sound levels are within the permitted limits. Should the sound level be above the permitted levels, Imperial would take measures to correct the situation.

Imperial stated that Mr. Lust's concerns have been adequately addressed, and proper mitigative measures have been taken. Furthermore, Imperial argued that nothing has been said to persuade the Board that its previous approval should be rescinded.

2.2 Views of the Interveners

Mr. Lust's residence is located within 1.5 km of the proposed compressor station. Mr. Lust argued that the proposed compressor station location is not acceptable because of the noise levels that would be generated. He stated that he does not agree with the methodology used by HFP in conducting the noise study. Mr. Lust claimed the ambient and predicted noise levels at his residence, as reported in the noise study, do not correctly reflect the actual effects of the proposed compressor station. He based his opinions largely on visits to other major compression facilities in the province and discussions held with residents living in the vicinity of those facilities.

Mr. Lust also questioned the ERCB's Noise Control Directive, claiming it was inadequate for rural settings. Mr. Lust stated that he would not be opposed to the compressor station if it could not be heard at his residence.

P. A. Young stated that she was there for the sole purpose of gathering information on the proposed compressor station and the hearing process. She also stated that she had concerns as to why Mr. Lust was not given proper notice with regard to the original hearing.

2.3 Views of the Board

The Board recognizes the general concerns expressed by Mr. Lust about increased industrial activity near his residence. The Board agrees that compression is required within the 5-km corridor south of Leduc and that the preferred site is an appropriate location for the facility. The Board acknowledges that a number of alternative locations exist within the 5-km corridor; however, in doing so, the Board expects that relocation of the proposed facility would simply transfer the impact to other residents without measurable benefits to the public. The Board is satisfied with the site selection process and with the mitigative measures proposed by Imperial to lessen the effects of the proposed compressor station in the applied-for location.

The Board believes that high-intensity lighting at the proposed compressor station is necessary for emergency purposes but expects Imperial to minimize the use of this lighting as much as practical. The Board accepts Esso's commitment to use low-intensity shrouded lights for the normal lighting of the site.

The Board accepts that the methodology used by HFP in conducting the Noise Impact Statement and the expected sound levels from the proposed compressor station are in accordance with the requirements of the ERCB Noise Control Directive. The report shows that road and railway traffic are likely to be the predominant sources of noise in the area. While it is recognized that intermittent noise can represent a different nuisance, the Board does not expect the impact of the proposed compressor station to result in an excessive imposition on local residents. The Board notes that the intent of the ERCB Noise Control Directive is not to guarantee that a resident will not hear sound from a particular facility; rather it aims for a situation where sound level increases will be kept to acceptable minimums and where indoor sound levels will not be adversely affected. The requirements of the ERCB Noise Control Directive are stringent and were developed after careful consideration, in consultation with the acoustical consulting community, industry, universities, rural landowners, government agencies, and ERCB staff.

The Board agrees with Imperial's plan to gather further baseline data and to conduct a noise survey after the facility is in operation. The Board notes Imperial's commitment to take whatever measures are necessary to reduce the sound levels if the recorded values are in excess of those permitted by the ERCB Noise Control Directive. The Board is satisfied that the proposed compressor station will not have an inordinate impact on the adjoining residents.

The Board concludes that Imperial's proposed compressor station is acceptable.

4 DECISION

The Board reconfirms the approval of Application No. 910505.

DATED at Calgary, Alberta, on 28 February 1992.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink*
Vice Chairman

K. G. Sharp, P.Eng.
Acting Board Member

J R Nichol

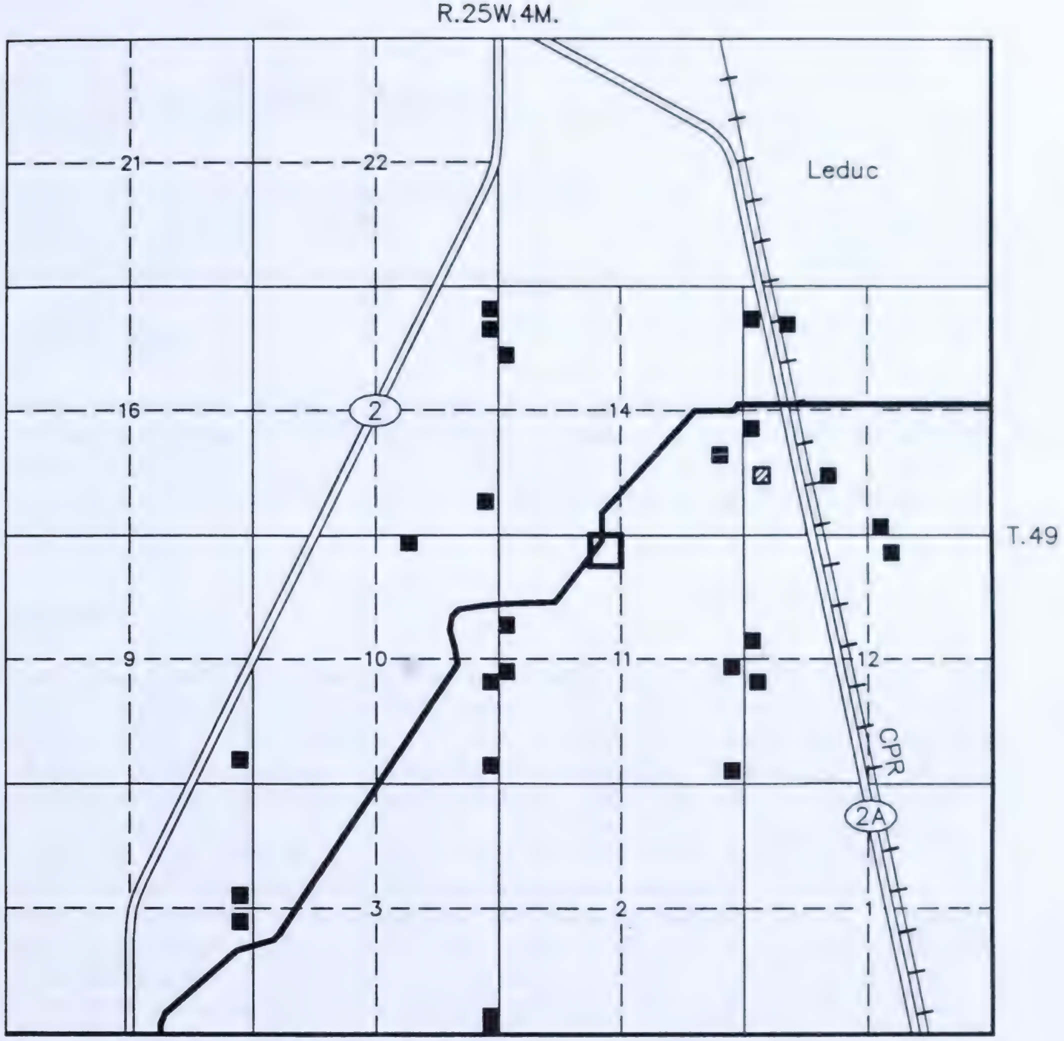
J. R. Nichol, P.Eng.
Acting Board Member

---

* F. J. Mink was not available for signing but concurs with the contents and with the issuance of this report.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The Imperial Pipe Line Company Limited (Imperial) D. G. Davis	T. J. Kehoe, P.Eng. C. D. Bird, P.Eng. P.H.R. Fathergill of Tera Environmental Consultants (Alta.) Ltd. L. D. Frank, P.Eng. of HFP Acoustical Consultants Ltd.
P. M. Lust	P. M. Lust
P. A. Young	P. A. Young
Energy Resources Conservation Board staff T. J. Pesta, P.Eng. P. K. Ferensowicz	



LEGEND

- ☐ Proposed 3.3 MW Compressor Station
- ▨ Mr. Lust's Residence
- ■ Other Residence Locations
- ━ Edmonton to Sundre Expansion Pipeline

LEDUC AREA
Application No. 910505
Imperial Pipe Line Company, Limited

D 91–6
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION BY MID-WEST GAS TRANSMISSION LTD.
TO CONSTRUCT A RAW GAS PIPELINE
GOLDEN SPIKE AREA

Decision D 91-7
Application 910285

1 APPLICATION

Mid-West Gas Transmission Ltd. (Mid-West) applied, pursuant to Part 4 of the Pipeline Act, for a permit to construct approximately 30 kilometres (km) of 168.3-millimetre (mm) outside diameter (OD) raw gas pipeline in the Golden Spike area from an existing gas plant at legal subdivision 8, section 27, township 51, range 27, west of the 4th meridian, to its existing Industrial Gas System (IGS) at Lsd 16-5-54-26 W4M.

2 HEARING

The application was considered at a public hearing in Edmonton, Alberta, on 2 and 3 May 1991, with F. J. Mink, P.Eng. (Chairman), and Acting Board Members K. G. Sharp, P.Eng., and J. R. Nichol, P.Eng., sitting. Mid-West stated that the raw gas pipeline would be an extension of the existing IGS system. It stressed that the pipeline is necessary to promote gas recovery from marginal wells in the area and also will maintain supply to its existing IGS system. Northwestern Utilities Limited (NUL) was the only party opposing the application. Upon the completion of its cross-examination of the Mid-West evidence, NUL withdrew its objection. NUL stated that it had tested and carefully considered the evidence of the applicant in these proceedings and concluded that under these circumstances it would not object to this application. It stressed that it believed that there is merit in close scrutiny of pipeline proposals, particularly where there is a potential for duplication of facilities. NUL considered that it was its right and obligation to test potentially duplicate proposals that may affect its operations. NUL suggested that when the Board assessed such proposals it should consider

- whether there are proven reserves and deliverability controlled by the applicant which are sufficient to support the applied-for facilities,
- whether the facility is fully supported by a market,
- whether bargaining with other companies to develop feasible transportation alternatives took place, and
- whether there are effects on existing integrated common carriers systems.

T. W. Morrison and P. A. Young, local landowners, attended the hearing to express their support for the Mid-West application.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Mid-West Gas Transmission Ltd. (Mid-West) J. P. Peacock, Q. C.	A. J. Bey, P.Eng. W. E. Sagert M. J. Selleck, P.Eng.
Northwestern Utilities Limited (NUL) J.E.E. Lowe	
T. W. Morrison	T. W. Morrison
P. A. Young	P. A. Young
Energy Resources Conservation Board staff C.J.C. Page T. J. Pesta, P.Eng.	

3 CONFIRMATION OF DECISION

In light of the evidence that has been presented and the fact that Northwestern Utilities Ltd. withdrew its objection, the Board approved the pipeline, as applied for by Mid-West Gas Transmission Ltd., at the hearing. The permit was subsequently issued upon receipt of the approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act.

DATED at Calgary, Alberta, on 30 May 1991.

ENERGY RESOURCES CONSERVATION BOARD

P. J. Mink, P.Eng.
Vice Chairman

K. G. Sharp, P.Eng.
Acting Board Member

J. R. Nichol, P.Eng.*
Acting Board Member

---

* J. R. Nichol, P.Eng., Acting Board Member, concurs with the contents and with the issuance of this report.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

HOME OIL COMPANY LIMITED AND Decision D 91-8
SCURRY-RAINBOW OIL LIMITED
HAMBURG AREA
COMMON PROCESSOR Application 901851
RATEABLE TAKE Application 901852
SPECIAL TWO-SECTION GAS DRILLING SPACING UNIT Application 901853
SWEET NATURAL GAS PIPELINE Application 910048
FUEL GAS PIPELINE Application 910049

1 INTRODUCTION

1.1 Applications and Hearing

Home Oil Company Limited, on behalf of itself and Scurry-Rainbow Oil Limited (collectively referenced hereinafter as the applicant), submitted applications under

- section 42 of the Oil and Gas Conservation Act (the Act) for an order declaring Shell Canada Limited to be a common processor of natural gas and natural gas liquids produced from the Hamburg Slave Point A Pool (the A Pool),
- section 23 of the Act for an order distributing production among certain wells in the A Pool,
- section 4.030 of the Oil and Gas Conservation Regulations for an order establishing sections 8 and 9 of township 97, range 11, west of the 6th meridian (97-11 W6M), as a special drilling spacing unit (DSU), with the target area being within the DSU and having sides 300 metres (m) from and parallel to the sides of the DSU, for the production of gas from the Slave Point Formation,
- section 45 of the Act for the aforementioned orders to be effective as of the date of these applications, and
- Part 4 of the Pipeline Act for approval to construct approximately 4.5 kilometres of 168.3-millimetre (mm) outside diameter natural gas pipeline from an existing well in legal subdivision (Lsd) 4 of section 9-97-11 W6M (the 4-9 well) to the existing Shell Canada Limited gas processing plant located in Lsd 11-29-96-11 W6M and for an associated 60.3-mm outside diameter fuel gas pipeline from the gas plant to the well.

The applicant also applied under section 37 of the Act for orders declaring NOVA Corporation of Alberta (NOVA) to be a common carrier of natural gas produced from the A Pool, and Novacorp Pipelines (Novacorp) to be a common carrier of natural gas liquids produced from the A Pool. However, the applicant withdrew these applications prior to the hearing; these applications were not discussed at the hearing or considered by the Board.

Gulf filed a submission in support of the applications; Encor, Husky, Shell, and Voyager et al submitted interventions opposing at least one of the applications; Columbia filed a submission that neither specifically supported nor opposed the applications.

The applications were considered at a public hearing commencing on 26 February 1991, before Board Members J. P. Prince, Ph.D. and B. F. Bietz, Ph.D., P.Biol., and Acting Board Member C. A. Langlo, P.Geol.

Table 1 lists those who appeared at the hearing and the abbreviations used in this report.

1.2 Background

The A Pool is a non-associated, sweet gas pool currently containing two producing wells located in Lsds 10-29 and 3-33-96-11 W6M (the 2/10-29 and 3-33 wells), which were drilled in 1983 and 1984, respectively, and which are owned by Shell. Production from the wells began in 1986 and totalled 1.45 billion cubic metres (10^9 m^3) to December 1990, with recent rates averaging about 873 thousand m^3/day (10^3 m^3/d). Production from the wells is being processed at the Shell Hamburg gas plant located in Lsd 11-29-96-11 W6M (see Figure 1). Shell has been proceeding with construction to expand the inlet capacity of the plant from 1896 x 10^3 m^3/d to 3044 x 10^3 m^3/d of raw gas and condensate. At the time of the hearing, the increased capacity was expected to be available about 1 August 1991. Subsequent to the hearing, Shell informed the Board by letter dated 8 May 1991 that it appeared that the expanded capacity of the plant could be available by 1 June 1991. Natural gas is transported from the Shell plant by NOVA, while natural gas liquids are transported from the plant by Novacorp.

Subsequent to the drilling of the 2/10-29 and 3-33 wells, three wells in Lsds 12-26 and 13-35-96-12 W6M and Lsd 2-6-97-11 W6M (the 12-26, 13-35, and 2-6 wells) were drilled in 1988, 1986, and 1988, respectively. Each well encountered a productive Slave Point reservoir and none of the wells are producing at the present time. At the time of the hearing, wells were being drilled in Lsd 4-10-97-11 W6M (the 4-10 well) and in Lsd 12-16-97-11 W6M. Subsequent to the hearing, Home informed the Board that the two wells have been abandoned.

The mineral interests in the general area of application are shown on Figure 2.

Shell, Encor, Home, Scurry, Voyager, and Canterra Energy Ltd. (represented at the hearing by Husky) signed a letter of agreement dated 23 February 1990 for the formation of a proposed unit, to be operated by Shell. The proposed unit, comprised of 28 sections as shown on Figure 1, includes the 2/10-29, 3-33, 12-26, 13-35, and 2-6 wells. Among other items, the letter of agreement specifies the equity interest of each participant and states that the unit would be effective on 1 November 1991 upon the participants executing a unit agreement and operating agreement prior to that date. The letter of agreement also indicates that processing capacity at the Shell plant would be available on the earlier of the date of the start-up of the plant expansion, or 1 August 1991.

In February 1990, Home drilled the 4-9 well on behalf of itself, Gulf, and Scurry and encountered a productive Slave Point reservoir. The standard one-section gas spacing in effect for the area has a target area within the section and having sides 300 m from and parallel to the sides of the section. The 4-9 well is located 332.6 m north and 97.2 m east in the section (surface location) and is off target towards section 8-97-11 W6M. The applicant estimated that the well is capable of producing in excess of 1.4 million (10^6) m^3/d of raw natural gas and 13 m^3/d of natural gas liquids against a pipeline pressure of 10 x 10^6 pascals. At the time of the hearing, the 4-9 well was not part of the proposed unit and was not tied in.

2 ISSUES

The Board considers the issues to be

- the delineation of the A Pool,
- the need for a common processor order and, if one is to be issued, the details of the order,
- the need for a rateable take order and, if one is to be issued, the method of distributing production among wells in the A Pool and other details of the order,
- the need for a special DSU, and
- the need to construct pipelines.

3 POOL DELINEATION

There was agreement among all hearing participants that the A Pool contains the proposed unit wells and the 4-9 well. In addition, volumetric and material balance reserves estimates for the pool were similar at about 12 x 10^9 m^3. However, significant conflicting evidence was presented at the hearing relating to the determination of a pool boundary. The hearing participants' interpretations of the pool boundaries are shown on Figure 3.

3.1 Views of the Applicant

Home utilized interpretation of geological, petrophysical, engineering, and seismic data to map the A Pool. It interpreted the A Pool reef buildup as consisting of several backstepping stages of growth, with relatively gently sloping reef margins. The applicant was of the view that because substantial dolomitization had occurred within the reef, the sparse well control and limited core recoveries do not allow for the development of a detailed facies model. Accordingly, the Home map does not reflect any specific reef model.

Home interpreted the 4-9 well to be within a high-energy grainstone shoal facies, based on peloids in the drill cuttings, and therefore not close to a reef edge. The applicant argued that the seismic character observed northeast of the 4-9 well, similar to that observed in the vicinity of the 3-33 well, represented a porosity distribution change. It interpreted the facies encountered in the 3-33 well to be reef rim, based on visual examination of core in association with seismic character, and positioned the southeast boundary of the pool adjacent to this well. The southwest pool limit was drawn to reflect the intersection of the gas/water contact, estimated from the 12-26 well, with structure on top of porosity. The remaining pool edges were drawn to reflect the position of non-porous off-reef wells, pool limits interpreted from available seismic data, and regional structural trends.

The applicant anticipated that its view of the pool would be supported by the 4-10 well which was in the process of being drilled during the hearing; however, it was opposed to delaying the decision on the applications to allow the use of data from the 4-10 well to assist in determining the northeastern boundary of the pool. In the applicant's view, the Board could review and revise the pool edges at a later date if requested to do so by any owner in the pool.

3.2 Views of Gulf

Gulf also employed an integrated approach to mapping the pool, using its geological model together with geophysical and petrophysical data, and reservoir engineering and pressure transient analyses. Gulf's mapping is consistent with the predominant facies in each well as determined from available core, drill cuttings, and log data. The intervener argued that while none of the various types of analyses used could independently define pool boundaries with precision, an integration of the data in a manner consistent with its reef model could provide a very good picture of the pool.

Gulf mapped the A Pool based on a typical Slave Point reef model in which primary porosity occurs along the edges of the carbonate bank. It interpreted the 3-33 well as being in the reef bank margin, and therefore close to the edge of the pool. Gulf also argued that porosity distribution could be detected on seismic. It submitted that seismic data confirmed the presence of porosity over sections 8, 9, and 10-97-11 W6M and extended its zero boundary to include these sections. The southwest limit of the A Pool was based on the intersection of the gas/water contact, as determined from the 12-26 well, with the structure on top of porosity.

Gulf argued that pressure transient analyses could be used to detect pool boundaries. It submitted that pressure transient analyses indicated boundaries 200 m from the 2/10-29 well, 600 m from the 3-33 well, and 1700 m from the 2-6 well. Gulf also interpreted the results of pressure transient analyses for the 4-9 well as showing boundaries at 900 m and 2000 m from the well.

Gulf expected that the 4-10 well would encounter the A Pool; however, it did not support delaying the decision on the applications to await the completion of drilling and testing operations at the well.

3.3 Views of Shell

Shell interpreted the A Pool boundary utilizing log data and extensive seismic control. However, it was of the view that limited core and log data did not allow for the development of a detailed reef model.

Shell interpreted a pool boundary close to the 4-9 well based primarily on seismic data. It based the southwest limit of the pool on the intersection of the gas/water contact in the 12-26 well with the structure on the top of the Slave Point Formation. Shell acknowledged that its mapping of the southeast boundary of the pool is inconsistent with its interpretation of the 3-33 well as a reef rim well; however, it argued that the boundary as depicted accounts for a well in Lsd 5-34-96-11 W6M which encountered minor reefal material indicating proximity to the reef bank edge.

On the basis of its seismic interpretation, Shell expected the 4-10 well to encounter off-reef basin facies of the Slave Point Formation. In its opinion, it is important that the data from the well be considered before a final decision regarding the application is made because the data will have a significant impact on pool interpretation.

3.4 Views of Encor

Encor also employed an integrated approach to mapping the pool, using geophysical, petrophysical, and reservoir engineering data together with a detailed geological reef model where the reef rim is more porous than the lagoon. It mapped an upper and lower facies unit within the pool, based on its analyses of fault trends, sequence stratigraphy, and facies interpretation made from core, drill cuttings, and log data.

Encor mapped the southwest limit of the pool as defined by the intersection of the gas/water contact in the 12-26 well with structure on top of the Slave Point Formation. It argued that the 4-9 well is on the seaward margin of the reef rim, and therefore in close proximity to the pool edge. Encor stated that the results of the well in Lsd 7-17-97-11 W6M, which encountered a Slave Point pool that is not in communication with the A Pool, are consistent with its interpretation. It interpreted a pool edge close to the 4-9 well based on seismic data and did not expect the 4-10 well to be within the A Pool.

3.5 Views of the Other Interveners

Columbia, Husky, and Voyager et al did not present interpretations of the pool outline.

Voyager et al indicated that it supported Shell's technical position and noted that its own geophysical interpretation of the A Pool is consistent with the outline presented by both Shell and Encor.

3.6 Views of the Board

The Board notes that the pool outlines for the southwestern limit of the A Pool submitted by Shell and Encor reflect a very optimistic interpretation based on limited well control and supplementary data. The Board believes that the pool edges submitted by Home and Gulf represent a more acceptable view of pool extent in this area and are consistent with the interpretation of a gas/water contact at -1785 m subsea in the 12-26 well.

Regarding the northeastern limit of the A Pool, the Board notes that significant interpretational differences exist between participants based on available seismic and pressure transient data. The Board notes that all participants acknowledged a change in seismic character near the 4-9 well. This change was interpreted by Shell and Encor as a pool edge and by Gulf and Home as a change in porosity distribution within the reservoir. In either case, all parties agreed that reserves underlie some portion of at least the south halves of sections 8 and 9-97-11 W6M. The Board believes, however, that the data presented raises considerable doubt that reserves underlie the north halves of these sections.

With regard to pressure transient analyses, the Board considers that the use of this data is highly interpretative and therefore of limited value in defining pool boundaries in this case.

The Board notes that most of the participants agreed that the 3-33 well represents a reef rim facies and is located close to the reef edge. Based on this observation, the Board does not believe that reserves can be reasonably allocated to sections 20 and 21-96-11 W6M.

The Board concludes that the A Pool should be defined as outlined on Figure 1.

4 NEED FOR A COMMON PROCESSOR ORDER AND, IF ISSUED, THE DETAILS OF THE ORDER

4.1 Views of the Applicant

Home submitted that producible reserves exist in the A Pool and that this gas requires processing before entering the NOVA pipeline system. The applicant noted that it had internal and external markets for the gas from the 4-9 well and had completed arrangements to transport the gas from the processing plant through the NOVA pipeline system as of the effective date of any orders resulting from the subject applications, or the date of a negotiated settlement among owners in the A Pool.

Home noted that the permeability of the pool is such that any well in the pool would be capable of producing the reserves in the pool; hence, significant drainage of the Home reserves underlying sections 8 and 9-97-11 W6M had occurred following the drilling of the 4-9 well because of ongoing production from Shell's 2/10-29 and 3-33 wells. Home argued that the rate of drainage could increase in future with increased capacity at the Shell plant. The applicant calculated that, assuming a gas in place of 12.2×10^9 m^3 for the pool and a recovery factor of 80 per cent, 6.7 per cent of the gas had been drained from the pool in 1990, and following expansion of capacity of the gas plant in 1991, 11.2 per cent of the gas could be drained annually.

Home stated that tie-in of the 4-9 well is not necessary for drainage of the pool. It would prefer to obtain its share of the reserves in the pool by including its lands and the 4-9 well in the proposed unit agreement, and it has continued to negotiate with unit participants. However, Home considered the most recent written offer — an additional 0.4 per cent equity in the proposed unit for the inclusion of section 9-97-11 W6M within the agreement area — to be clearly unreasonable and technically unsupportable, as the 4-9 well is petrophysically equivalent to the best wells in the pool. Because unitization negotiations respecting the 4-9 well were not succeeding while drainage of its reserves continued at a significant rate, Home requested access to the Shell plant on an immediate basis in order to produce the 4-9 well competitively with other wells in the pool. Because Shell offered to allow Home access to the plant on either 1 August 1991 or the date that expanded capacity is available, Home considered the offer to be unacceptable because of the additional drainage of its reserves which would occur. The applicant also pointed out that sections 8 and 9-97-11 W6M are not part of the 23 February 1990 agreement and therefore the terms of that agreement do not apply to those sections.

The applicant argued that the expanded Shell plant would have sufficient capacity to process gas from the A Pool at a reasonable rate and represents the most practical and desirable method of processing the gas produced from the 4-9 well. A second new plant in the area would constitute an unnecessary and undesirable proliferation of facilities and may not be an environmentally acceptable solution. Home acknowledged that the economics of a new plant which could process gas from the 4-9 well and from other wells outside the A Pool would likely be similar to the economics of using the Shell plant. However, the applicant considered it impractical to build a new plant, in any event, because of the severe and unacceptable drainage of its reserves which would occur during the estimated 2-year construction period.

Home also submitted that it would be less economically attractive to transport gas from the 4-9 well to the existing gas plant located in Lsd 5-32-98-7 W6M than to use the Shell plant. It submitted that the facility has limited firm capacity for processing gas outside the immediate area without expansion, and would require large amounts of capital for production facilities and pipelines, making this alternative impractical.

The applicant concluded that in view of the failure of negotiations to include its lands in the proposed unit or to obtain immediate access to the Shell gas plant for competitive operations, it had no reasonable alternative but to request a common processor order.

Home requested that the common processor order be made effective as of the date of its application, 31 October 1990. The applicant suggested that the retroactive portion of production be achieved by a cutback of production from only the producing Shell wells. It did not consider it inequitable that it should have access to the plant for gas from the 4-9 well prior to other owners in the A Pool who had signed the 23 February 1990 agreement. Home pointed out that it had also signed that agreement and was fully prepared to abide by the agreement for its lands within the proposed unit; however, sections 8 and 9-97-11 W6M are not subject to that agreement and there has been and continues to be significant drainage of the reserves underlying those sections. The applicant argued that, as negotiations to include these lands in the proposed unit area have failed, obtaining access to the plant for competitive operations and the best economic yield for the lands would be a prudent business decision. Home stated that the 4-9 well was not initially tied in because of unit negotiations; however, tie-in plans are now under way and construction could commence as soon as regulatory approvals are received and the weather permits.

Finally, Home was opposed to a Shell request that any common processor order issued be subject to the condition that the applicant's share of production from the A Pool be processed exclusively at the expanded Shell plant. The applicant argued that if the 4-9 well were produced competitively, it would want to have the option of taking the gas to another plant if it were economically desirable. Home had no objection to the Shell request that any common processor order issued also be subject to the condition that the maximum capacity of the Shell plant made available to process gas from the A Pool be 3×10^6 m^3/d.

4.2 Views of Gulf

Gulf favours unitization as a means to eliminate unnecessary wells and facilities and to protect correlative rights. It contended that it had made every effort to expand the proposed unit agreement to include sections 8 and 9-97-11 W6M. However, negotiations have been frustrated by differences in interpretation of the location of reserves, as illustrated by the last written offer of 0.2 per cent equity to Gulf in the proposed unit. Gulf argued that the rapid rate of drainage precludes prolonged negotiations; it estimated that drainage of pool reserves is in the order of 30 to 45×10^6 m^3/month and this could double when the gas plant expansion is completed. Gulf submitted that, unlike Shell, it has no current means of obtaining its fair share of the gas from the A Pool and no reasonable future means as a participant in the proposed unit.

Gulf submitted that there is a consensus that the Shell plant as expanded is adequate for processing all of the gas in the A Pool. In Gulf's opinion, a new plant in the area would be unnecessary, contrary to the Board's policy on plant proliferation, and would not meet Gulf's immediate requirement to alleviate the drainage of its reserves, which would continue during the 2 years needed to construct and commence operations at a new plant. The intervener concluded that, if unitization fails, it would require a common processor declaration in order to obtain access to the Shell plant and allow it to market an equitable share of gas from the A Pool.

Gulf supported the Home request that the common processor declaration be made effective as of the date of the application, 31 October 1990. It suggested that the retroactive portion of production be achieved by restricting the rate of production from the Shell wells from the date of the Board decision on the application until such time as the 4-9 well made up its share of production, as tracked from the date of the application. Gulf did not consider it inequitable that it should have access to the plant for gas from the 4-9 well prior to other owners in the A Pool who signed the proposed unit agreement and who would not have access to the plant prior to the earlier of 1 August 1991 or the date the expanded capacity becomes available. The intervener speculated that the unit participants would have taken drainage into account when negotiating an equity share in the unit and thus would be protected against drainage to some extent. However, Gulf is not a signatory to the proposed unit agreement and has no such protection. Therefore, Gulf requested the effective date of the common processor declaration to be made retroactive to the date of the Home application.

4.3 Views of Shell

Shell stated that it is committed to proceeding with the proposed unit agreement and has been endeavouring to negotiate an enlargement of the proposed unit to include the 4-9 well. It said that the remaining outstanding issue with respect to expansion of the proposed unit is the equity split that would result from the inclusion of additional land. Shell is prepared to make capacity available in the plant for gas produced from the 4-9 well on the same terms as specified in the proposed unit agreement, with access on the earlier of 1 August 1991 or the date the expanded capacity is available. The capacity shared by the owners in the pool would be as set out in the proposed unit agreement as modified by the share agreed to by the owners of sections 8 and 9-97-11 W6M, or as established by a rateable take order issued by the Board. Shell concluded that the application for the declaration of a common processor should be denied on the basis that reasonable arrangements for use of processing capacity could be made.

Shell submitted that the capacity of the expanded plant would be sufficient to process reserves from the A Pool at reasonable rates of take. In its opinion, a second plant to process reserves from the pool would be neither necessary nor desirable.

If, notwithstanding Shell's position on the application, a common processor order were issued, Shell requested that the effective date of the order be the earlier of 1 August 1991 or the date of start-up of the plant expansion. The intervener did not consider it inequitable to delay providing drainage relief to the mineral interest holders of reserves underlying sections 8 and 9-97-11 W6M. It did not characterize the drainage from the pool as unusually high. While Shell acknowledged that Gulf was not a signatory to the proposed unit agreement, it saw no reason why reserves outside the agreement area should be on any different production timetable than had been established within the agreement area. Shell also observed that Home had agreed to the production timetable for its interests within the proposed unit area, and it contended that the applicant, in being a participant in the proposed unit agreement, was a party to cooperative development of the pool.

Shell requested that any common processor order issued be subject to the conditions that the maximum capacity of the Shell plant made available to processing gas from the A Pool be 3×10^6 m^3/d, and that the applicant's share of gas production from the A Pool be processed exclusively at the Shell plant.

The intervener requested the latter condition because it was concerned that, having made capacity available at the plant for gas produced from the 4-9 well in accordance with its obligation under a common processor order, it would not be free to fill that capacity with other gas if production from the 4-9 well were processed at another plant, and the Shell plant could therefore be underutilized.

4.4 Views of Encor

Encor submitted that eventual unitization would be the preferred means of developing the A Pool. It noted that negotiations to include the 4-9 well in the proposed unit agreement failed on the issue of equity share in the expanded proposed unit. It expressed the view that once the Board has determined a fair allocation of production in the A Pool, either the parties would be able to move quickly to unitization or the owners of the 4-9 well would be provided access to the Shell plant in a reasonable time frame. Further, Encor argued that reasonable arrangements for processing gas produced from the 4-9 well could be made, since Shell would provide capacity even if the well remained outside the proposed unit. Arrangements for processing capacity have been established in the proposed unit, and the same terms and conditions were offered to Home and Gulf for gas produced from the 4-9 well during negotiations to expand the proposed unit; the only issue remaining to be resolved is the share of plant capacity to be made available. Encor concluded that if a rateable take order is issued, nothing additional is required that would be provided by a common processor order, and therefore the order is likely to be unnecessary and redundant.

If, however, a common processor order is issued, Encor submitted that the effective date of the order should be concurrent with the production timetable established by the proposed unit agreement. The intervener expressed the concern that, if Home and Gulf commence production from the 4-9 well under a common processor order at an earlier time than would be possible under the proposed unit agreement, other pool owners not on production would be potentially prejudiced and may be encouraged to abandon the proposed unit in favour of earlier production under the common processor order. Abandonment of the proposed unit could result in unnecessary costs and environmental impacts because of additional drilling and tie-in of wells not required to drain the pool.

Encor did not consider it inequitable to delay providing relief from drainage of the reserves underlying sections 8 and 9-97-11 W6M. The intervener stated that, contrary to Gulf's speculations, Encor had not gained additional working interest in the proposed unit to compensate for drainage that would occur up to the effective date of the proposed unit. In any event, Encor was of the view that the pool drainage of 4 to 4.5 per cent annually is low to medium in the context of plant capacity and the oil and gas industry in general in Alberta. Furthermore, although Gulf is not a party to the proposed unit agreement, that agreement provides an opportunity to Gulf which would not otherwise be available. Because of the agreement, production could commence from the 4-9 well on the earlier of 1 August 1991 or the date the plant expansion becomes available, some 1.5 years after the well was drilled, and earlier than would be possible under normal competitive operations. Encor noted, for example, that it had taken Shell some 3 years after drilling a successful well in the A Pool to commence production, and it appears that it will take Columbia over 2 years to commence production from its well in Lsd 10-14-97-11 W6M (the 10-14 well).

4.5 Views of Columbia

Columbia did not comment on the need for a common processor order or the details of any common processor order that may be issued.

Columbia confirmed that the target date for start-up of its proposed gas processing plant to be located in Lsd 6-14-97-11 W6M is 1 November 1992. The plant would process gas produced from the 10-14 well and other wells planned for the area. Columbia had discussions with Shell respecting access to another expansion of the Shell plant; however, it was Columbia's understanding that the expansion, if it occurred, would not be operational until 1993. Columbia said that it preferred to have gas on stream in 1992 and accordingly, it is presently continuing with arrangements to build its own gas processing plant.

4.6 Views of Husky and Voyager et al

Husky and Voyager et al did not comment on the need for a common processor order or the details of any common processor order that may be issued.

4.7 Views of the Board

The Board considers that an applicant requesting a common processor declaration would be required to demonstrate to the Board's satisfaction that

- producible gas reserves exist and gas processing facilities are needed,
- reasonable arrangements for the use of processing capacity in the existing plant could not be agreed on by the parties, and
- a common processor order represents the most economically feasible and desirable method to process the gas in question.

In considering the effective date of the common processor order, which under section 45 of the Act may be made retroactive to the date of the application, the Board would consider fairness, previous negotiations among the parties, and the impact of the effective date on the participants.

The Board accepts the evidence and statements that there are producible reserves in the A Pool, that the gas is of such composition that it requires processing before entering the NOVA system, and that the applicant has markets and NOVA transportation available for the subject gas. Further, the Board notes that all of the major parties participating at the hearing agreed that the Home/Gulf reserves underlying sections 8 and 9-97-11 W6M are being drained as a result of production from the Shell 2/10-29 and 3-33 wells, although disagreeing on the relative significance of the drainage. The demonstrated permeability and deliverability of the A Pool indicate to the Board that the pool is one of the most prolific in the province. The Board concludes that there is a significant rate of drainage occurring from the pool and subsequently from the Home/Gulf lands which would be likely to continue in the future if the issues preventing production of the reserves involved are not resolved. The Board also concludes that the Home/Gulf reserves require processing facilities.

The Board notes that all of the parties involved agree that unitization represents the best means of developing the A Pool. In addition, the Board notes that negotiations to include the 4-9 well in the proposed unit or to produce the 4-9 well on a competitive basis failed on the issues of equity shares in the expanded unit, the capacity Home/Gulf would receive at the Shell plant, and/or the timing of access to the plant. Further, the last written offer received by Home/Gulf of a 0.4 per cent share of reserves for section 9-97-11 W6M appears to the Board to be unreasonably low. The Board concludes that the applicant has been unable to make reasonable arrangements for use of processing capacity at the Shell plant.

The Board notes that there is general agreement that the Shell plant as expanded would have sufficient capacity to process the reserves from the A Pool, and that a second, new plant to process gas from the pool would be unnecessary. The Board is of the opinion that the drainage which would occur during the construction of a new plant or the expansion of the plant in Lsd 5-32-98-7 W6M would be unacceptable. The Board concludes that the Shell plant offers the most practical, economic, and timely means of processing gas produced from the 4-9 well and believes that the issuance of a common processor order would be appropriate.

The Board notes an argument was made at the hearing that, if a rateable take order were issued, a common processor order would be unnecessary. However, a rateable take order would not unequivocally assure access by all parties to the gas processing plant.

In determining the effective date of the common processor order, the Board observes that it would not be unusual, under normal competitive operations, for 2 or more years to be required in order for an operator to make arrangements to produce a well drilled in a remote location such as the Hamburg area partly because of difficult surface access. If granted, an effective date of 31 October 1990 for the common processor order would, in the Board's view, provide Home/Gulf a significant advantage over other operators in the pool. Further, the Board has regard for suggestions that an early effective date might cause parties in the proposed unit to demand that their gas be taken under the common processor order and lead to disintegration of the proposed unit. This could lead to increased drilling and associated undesirable effects on operational efficiency and the environment. Having regard for the information provided to the Board that the expanded capacity of the Shell gas processing plant could become available as early as 1 June 1991, the Board believes it unnecessary to address the request of some interveners that a common processor order, if issued, be made effective on the date the plant expansion becomes available. In view of the foregoing, the Board concludes that the order should be made effective on the date of the decision report.

The Board sees no reason to make the common processor order subject to the condition that the applicant's gas be produced exclusively at the Shell plant. A common processor would be obligated to process gas made available from the pool without discrimination; however, in the Board's view, if the applicant chooses to process gas from the 4-9 well at another plant, Shell would be free to fill the capacity of the plant with other gas. Given the nature of the pool, Shell should be able to do this easily using existing wells in the A Pool. Additionally, the Board sees no reason to make the common processor order subject to the condition that the maximum capacity of the Shell plant made available to process gas from the A Pool be 3×10^6 m^3/d. Shell, as operator of the plant, would be in a position to determine what capacity should be available for A Pool gas at any time and a condition in the order specifying that capacity appears to be unnecessary.

5 NEED FOR A RATEABLE TAKE ORDER AND, IF ISSUED, THE DETAILS OF THE ORDER

5.1 Views of the Applicant

Home submitted that in view of the drainage of its reserves and its unsuccessful attempts to negotiate a satisfactory agreement to include the 4-9 well in the proposed unit or to produce the well on a competitive basis (as described in Section 4.1 of the report), it had no alternative but to apply for a rateable take order to ensure that it obtains an equitable share of gas from the A Pool. The applicant noted that a rateable take order could also provide a basis for expanding the proposed unit.

Home proposed that production from the A Pool be distributed between its 4-9 well and the proposed unit wells in proportion to their associated hydrocarbon pore volumes, assuming equal drainage areas for each well. Using net pay, average porosity, and average water saturation values for each well, Home calculated that 24.6 per cent of the production should be allocated to the 4-9 well, and 75.4 per cent to the unit wells. The applicant submitted that this method of allocation was in accordance with Guide G-32 in that a formula-type approach could be adopted where there are large differences among the parties involved in mapping the pool. The applicant argued that, with only six wells in the pool, the available data allow for a wide range of contour options, and accordingly, no single map would be sufficiently accurate to determine an equitable allocation of production. Home also contended that, if allocation were based on mapping, there would be no guideline for accommodating new wells, with the possible result of additional applications being submitted to the Board for allocation in the future.

Notwithstanding the above proposal, Home said that, in order to prevent the unnecessary drilling of additional wells in the A Pool, it would support an allocation on the basis of hydrocarbon pore volume as calculated using a multiple-section validated area for each well. The applicant proposed that whole sections be included in each validated area, but if any partial sections were to be included, any method of assigning partial sections be applied equally to the lands within and outside the proposed unit. The applicant suggested that each existing well in the pool validate from two to four sections, as follows:

Well	Sections Validated by Well
2/10-29	29, 30, 31, and 32-96-11 W6M
3-33	33-96-11 W6M and 4-97-11 W6M
12-26	25 and 26-96-12 W6M
13-35	35 and 36-96-12 W6M and 1-97-12 W6M
2-6	5 and 6-97-11 W6M
4-9	8 and 9-97-11 W6M

The applicant calculated that, using this validated-area approach, 19.3 per cent of the pool production should be allocated to the 4-9 well and 80.7 per cent to the wells in the proposed unit.

In determining the hydrocarbon pore volume to use in an allocation formula, Home noted that porosity determination was the most contentious issue among the parties involved. The applicant used the density log as its primary tool for porosity determination, with the neutron and sonic logs as secondary tools. Calculated porosity values were corroborated either by core-log or log-log matching.

Home used a technique of applying the differentials between the drilling mud hydrostatic pressure and formation pressure to correct the porosity values in the 2/10-29 and 2-6 wells to account for gas effects. It did not find it necessary to apply gas corrections for other wells. The Home values for net pay, porosity, water saturation, and the hydrocarbon pore volume resulting from these values for each well in the A Pool are shown on Table 2.

In the applicant's view, the Board would not need to specify accounting procedures to track production from the A Pool in relationship to the ratable take order, as industry has become very adept at handling such matters. The applicant requested that the order be effective as of the date of its application, 31 October 1990. It argued that, although there is no specific provision in Part 7 of the Act indicating that a rateable take order could be made effective prior to the date of issuance, as there is under Part 10 of the Act for common processor orders, the Board has very broad discretion under section 23 of the Act and has a clear and unquestionable jurisdiction to apportion production as of the date of the application. The applicant provided reasons for the requested effective date of both the rateable take and common processor orders, and suggested the manner in which the retroactive portion of production could be handled, as described in Section 4.1 of the report.

5.2 Views of Gulf

Gulf submitted that unitization might be able to occur on the basis of a rateable take order. If unitization negotiations fail, Gulf would require the rateable take order to obtain an equitable share of reserves from the A Pool.

Gulf proposed that production from the A Pool be distributed between sections 8 and 9-97-11 W6M and the unit in proportion to the hydrocarbon pore volume associated with each well as calculated over a multiple-section validated area. It used the same validated areas as Home and calculated that 15.8 per cent of pool production should be assigned to sections 8 and 9-97-11 W6M and 84.2 per cent to the unit.

Gulf submitted that the allocation on the basis of wellbore hydrocarbon pore volume over a multiple-section validated area would be comparable to the allocation obtained if mapped hydrocarbon pore volume were used. It noted that the interior of the pool could be contoured in a variety of ways that would honour the well data, reserves estimates, and pool edge determinations. Using its map, Gulf calculated that 13.0 per cent of the pool reserves underlie sections 8 and 9-97-11 W6M. However, it argued that the reserves underlying undrilled areas outside sections 8 and 9-97-11 W6M and the proposed unit should also be shared in a proportionate manner. On this basis, it calculated that an additional 1.6 per cent of pool reserves should be allocated to sections 8 and 9-97-11 W6M for a total allocation based on mapping of 14.6 per cent.

Gulf used a combination of all data, including core, to obtain net pay, porosity, and water saturation values to use in the allocation formula and in mapping the reserves. It used the density log calibrated to core for porosity determinations. The core data were used together with curve-shape matching to reconstruct the density curve in rugose wellbores. Gulf adjusted the porosity determination for gas effects on all wells by using the core to log porosity relationship to establish correct matrix values.

The Gulf values for net pay, porosity, water saturation, and the hydrocarbon pore volume resulting from these values for each well in the A Pool are shown on Table 2.

Gulf accepted the view that the Board does not have the jurisdiction to make a rateable take order effective prior to the date of issuance of the order, and it requested that an effective date for the order be set as soon as possible because of the severe drainage that is occurring from its property.

5.3 Views of Shell

Shell submitted that the Board should grant the application for an order distributing production from the A Pool because the order could provide a basis for the parties involved to resume negotiations and conclude an agreement to enlarge the proposed unit to include the Home and Gulf lands.

Shell proposed that production from the A Pool be distributed in proportion to the reserves underlying sections 8 and 9-97-11 W6M and the proposed unit lands, as defined by mapping. It argued that once hydrocarbon pore volumes for each well and the pool edges are set, Shell's mechanical method of contouring minimizes the interpretation required to produce a map. Shell submitted that its hydrocarbon pore volume map of the A Pool should be used as a basis for allocating reserves. On this basis, 2.1 per cent of pool production would be allocated to sections 8 and 9-97-11 W6M and 97.9 per cent to the proposed unit lands. Shell noted that the Home map would provide an allocation of 11.4 per cent of pool production to sections 8 and 9-97-11 W6M.

In the event that the Board is not prepared to distribute production from the A Pool in accordance with Shell's preferred method, Shell suggested an alternative solution based on wellbore hydrocarbon pore volumes and multiple-section validated areas. This would avoid the drilling of unnecessary wells provided the calculations take into account the specific information available with respect to the geology and reservoir characteristics of the pool. Shell proposed that the same validated areas as suggested by Home be used, except for sections 8 and 9-97-11 W6M, where it proposed that only the south halves of the sections be used. On this basis, Shell calculated that 7.1 per cent of pool production would be allocated to sections 8 and 9-97-11 W6M, and 92.9 per cent to the proposed unit.

In determining porosity for the calculation of hydrocarbon pore volume values, Shell used sonic log data and core where available; in the absence of core, it used a comparison of a core porosity to sonic log transit time. Intervals where cycle skipping occur were edited and porosity for those intervals calculated using the density or neutron-density cross-plot methods. Shell noted that the microlog correlated well with core porosity and permeability and with sonic porosity, and provided a minimum value for thickness of permeable rock for each well. The Shell values for net pay, porosity, water saturation, and the hydrocarbon pore volume resulting from these values for each well in the A Pool are shown on Table 2.

Shell stated that the rateable take order should be effective on the earlier of 1 August 1991 or the date the plant expansion becomes available, or upon the date of tie-in of the 4-9 well, if the tie-in occurs subsequent to the start-up of the plant expansion. Shell justified the requested effective date of both the rateable take order and any common processor order that may be issued as described in Section 4.3 of the report. The intervener stated that, in any event, the Board lacked the jurisdiction to make a rateable take order effective prior to the date of issuance of the order as requested by the applicant. Shell further submitted that, assuming the Board accepted Shell's preferred allocation method, the rateable take order should be subject to the condition that the 2.1 per cent of production assigned to the 4-9 well could not be changed except as a result of drilling a well in the northeast quarter of the target area in section 9-97-11 W6M or, if Shell's alternative allocation method were accepted, the order should be subject to the condition that the 7.1 per cent of production assigned to the south halves of sections 8 and 9-97-11 W6M could not be changed except as a result of drilling a well in the north half of section 8 or 9-97-11 W6M. Shell also said that the Board should specify the time frame for the production balancing to be used in conjunction with the rateable take order. The accounting mechanism should provide sufficient flexibility to protect the parties from unforeseen interruptions in production. The intervener suggested that accounting on an annual basis would be appropriate; production balance would be more difficult on a shorter time frame. Finally, Shell submitted that the rateable take order should be granted on the basis that plant capacity for the A Pool be restricted to a maximum of 3 x 10^6 m^3/d.

5.4 Views of Encor

Encor submitted that it would be appropriate for the Board to issue a rateable take order. Once the order is issued, either the parties involved would be able to use the order as a basis to move quickly to unitization, or the owners of the 4-9 well would be provided access to the Shell gas plant in a reasonable time frame.

Encor proposed that production from the A Pool be distributed on the basis of hydrocarbon pore volume mapping in proportion to the reserves underlying sections 8 and 9-97-11 W6M and the proposed unit lands. Using its own map, Encor calculated that 2.46 per cent of pool production should be allocated to sections 8 and 9-97-11 W6M, and 97.54 per cent to the proposed unit lands. It noted that the various mapping options presented at the hearing resulted in allocation of pool production ranging from about 2 to 13 per cent to sections 8 and 9-97-11 W6M, and it submitted that a fair allocation would fall within this range. Encor urged the Board not to reject mapping as the basis for a decision on allocation on the grounds that such mapping would not be precise. It argued that there would never be sufficient data to precisely identify and quantify the location of reserves in any pool. An allocation based on a hydrocarbon pore volume map produced from the best available information, and assigned to sections 8 and 9-97-11 W6M and the proposed unit lands, would be consistent with the proposed unit agreement which acknowledges reserves underlying undrilled tracts, and would minimize the incentive to drill any additional wells in the future. Encor stated that additional wells would be unnecessary for drainage of the pool. It opposed any allocation method based on a mechanical set of rules, including the Home proposal and the proposals incorporating multiple-section validated areas, because such methods could result in an inequitable allocation of pool production, and would recognize only a portion of the reserves underlying undrilled tracts within the proposed unit area.

Encor submitted that it had used a consistent methodology to determine the hydrocarbon pore volume for each well in the pool. In particular, a single-porosity method was adopted based on a hierarchy of porosity-measurement reliability. Core porosities were used where available. Lithology-corrected sonic porosities were used in the remainder of the porous intervals in each well, with the exception of the 2-6 well, where a lithology and hydrocarbon-corrected density methodology was used. Cycle skipping on the sonic log data due to gas effect was edited and the density log used to calculate porosity over those intervals. The Encor values for net pay, porosity, water saturation, and the hydrocarbon pore volumes resulting from these values for each well in the A Pool are shown on Table 2.

Encor submitted that the effective date of the rateable take order should be the earlier of 1 August 1991 or the date the plant expansion becomes available to be consistent with the production timetable established in the proposed unit agreement. It justified the requested effective date of both the rateable take and any common processor order that may be issued as described in Section 4.4 of the report.

5.5 Views of Columbia

Columbia did not comment on the need for a rateable take order or the details of any rateable take order that may be issued.

5.6 Views of Husky

Husky submitted that production from the A Pool should be distributed in proportion to the reserves associated with the 4-9 well and the proposed unit lands, as defined by hydrocarbon pore volume mapping. It agreed with Encor's view that an equitable allocation of production to sections 8 and 9-97-11 W6M would be from 2 to 13 per cent, as obtained from the various hydrocarbon pore volume maps presented at the hearing. Husky noted that the regulatory solution least favourable to the 4-9 well owners would be to apply an off-target penalty to the Home hydrocarbon pore volume figures to obtain an allocation for the well of 1.4 per cent of pool production. The intervener opposed allocation based on the Home proposal, because the 24.6 per cent allocation to sections 8 and 9-97-11 W6M resulting from the proposal is not supported by any hydrocarbon pore volume mapping presented at the hearing and because it ignores the undrilled sections in the proposed unit and thus could result in the drilling of unnecessary wells.

Husky did not present an interpretation of hydrocarbon pore volumes associated with each well in the A Pool or comment on the hydrocarbon pore volumes or methodologies presented by other hearing participants.

5.7 Views of Voyager et al

Voyager et al submitted that any allocation of production from the A Pool should be between the 4-9 well and the proposed unit lands and it supported the technical position presented by Shell. The intervener argued that the effective date of any rateable take order should be consistent with the production timetable set out in the proposed unit agreement, and no new production-sharing arrangement should be allowed preferential treatment relative to the proposed unit agreement.

5.8 Views of the Board

The Board considers that an applicant requesting an order distributing production among wells in a pool would be required to demonstrate to the Board's satisfaction that it is being deprived of the opportunity to obtain its share of the production from the pool. The Board would determine whether or not the applicant has and will continue to have a reasonable opportunity to produce gas in proportion to the reserves associated with its well. The applicant must show that drainage is actually occurring as a result of the applicant not having an opportunity to produce its share of gas.

As indicated in Section 4.7 of the report, the Board agrees that the reserves underlying sections 8 and 9-97-11 W6M are being drained and would continue to be drained because of the failure of negotiations to expand the proposed unit, or to make reasonable arrangements to allow competitive production of the 4-9 well. Further, the Board is satisfied that the applicant has made reasonable attempts to resolve the drainage matter. Therefore, the Board would be prepared to issue a rateable take order to provide for equitable withdrawals from the pool.

Although the Board acknowledges the possibility of duplication of some of the intended effects of a common processor order with those of a rateable take order, considering the agreement among the parties involved that a rateable take order should be issued, the Board believes that any such duplication would not be significant. A rateable take order will be useful in eliminating uncertainty regarding the appropriate allocation of production from the A Pool.

While it is appropriate to apportion production on the basis of reserves, where there are insufficient data to map a pool's edges or the distribution of reserves within the pool with a reasonable degree of confidence, it is also appropriate to use an allocation formula such as described in Guide G-32. In this case, the Board notes that each of the four hydrocarbon pore volume maps of the A Pool presented at the hearing would result in a significantly different allocation of production to wells in the pool. Therefore, the Board is not prepared to allocate production on the basis of hydrocarbon pore volume mapping, but will apply an allocation formula. The allocation formula selected should not encourage the drilling of unnecessary wells, so the Board is prepared to consider the use of multiple-section validated areas as part of the method of allocation that is appropriate for the A Pool. Use of such a formula also provides a guideline to allocate production to any new wells which may be drilled in the A Pool.

In considering the details of the allocation formula appropriate in this particular case, the Board considered three primary factors. First, the variation in the wellbore parameters among wells in the pool justifies using individual wellbore water saturation and porosity values in addition to the net pay values historically used in an allocation formula. Second, all of the hearing participants requested that production from the pool should be distributed between either the 4-9 well, or sections 8 and 9-97-11 W6M, and the proposed unit area. There appears to be no reason that production should be allocated to individual wells in the proposed unit unless the unit does not materialize. Finally, the Board notes the concern raised at the hearing that an allocation formula that does not account for undrilled lands which are acknowledged by the proposed unit agreement to have reserves could result in the drilling of wells which are not required to drain the pool. Use of the validated-area concept discussed at the hearing, together with allocating production to the proposed unit as a whole, should minimize these concerns.

The Board considers that a validated area should include only tracts where there is a reasonable likelihood that there are reserves. The hearing participants proposed identical validated areas within the proposed unit, and the Board is prepared to use these. For sections 8 and 9-97-11 W6M, the Board is of the view that there is sufficient uncertainty regarding the delineation of the pool and the distribution of reserves in the area of the two sections to justify including only the south halves of each of the sections in the area validated by the 4-9 well, as suggested by Shell. The validated areas and the formula the Board believes would be appropriate to use to distribute production from the A Pool are shown on Figure 4 and Table 3, respectively.

In determining the hydrocarbon pore volume to use in the allocation formula, the Board believes that a consistent approach utilizing available log and core data is appropriate in calculating reservoir parameters. The Board notes that a variety of approaches to calculating porosity were used by hearing participants, and that porosity determination was one of the most contentious issues in unit negotiations.

The Board believes the effects of vuggy porosity and gas on the sonic log of some wells may result in optimistic porosity estimations. The methods utilized to remove these effects are quite interpretative and were generally not consistently applied to all wells in the A Pool. Generally, the Board notes that in comparison to other methods of net pay determination, the net pay values determined by the sonic log method are consistently higher.

The Board believes that the neutron and density cross-plot methodology utilized in gas-bearing zones results in porosity values which compare closely to core porosity. Since appropriate logs were available for all wells in the pool, the Board adopted this method for porosity determination.

The Board has determined the wellbore parameters shown on Table 2 for each well in the A Pool utilizing available data and the method described above. Using these parameters in the allocation formula shown on Table 3, together with the validated areas as previously discussed, the Board concludes that it would be equitable to allocate 7.8 per cent of pool production to the 4-9 well and 92.2 per cent to the proposed unit.

The Board notes with interest the argument from Home that the Board could make the rateable take order retroactive. However, for the reasons set out in Section 4.7, the Board is not prepared to issue a retroactive order and so does not consider it necessary to assess that argument here. The issue of retroactivity will be considered as part of an upcoming review of related legislation. Further, for the same reasons set out in Section 4.7 of the report respecting the effective date of the common processor order, the request to make the rateable take order effective at a future date is no longer applicable. Accordingly, the Board would make the order effective as of the date of this report, consistent with the effective date of the common processor order.

The Board agrees with Home that it should not be necessary to specify the time period over which production balancing under the rateable take order should occur. If the parties are unable to agree on the period, they may apply to the Board to amend the rateable take order to specify a particular time period.

Finally, in accordance with its view respecting the common processor order set out in Section 4.7 of the report, the Board considers it unnecessary to specify what plant capacity should be made available to the A Pool under the rateable take order. In addition, the Board notes that there is provision under existing legislation to thoroughly review proposed changes to the allocation set out in the order and sees no reason to include any conditions in the order, as requested by Shell, respecting how proposed changes should be handled.

6 NEED FOR A SPECIAL DSU

6.1 Views of the Applicant

Home submitted that, although its interpretation of the A Pool indicates that there would have been equivalent on-target locations for a well on sections 8 and 9-97-11 W6M, it had drilled the 4-9 well off target on the chosen location to meet all of the following criteria: the well would be located directly on a specific seismic line, the well would be drilled at the point where the optimum location to encounter productive reservoir is clearly indicated on the seismic line, the well would be as close as possible to section 8-97-11 W6M to allow evaluation of the section which was posted for sale at the time, and the well would remain on target to the south to avoid affecting the correlative rights of mineral interest holders in that direction.

Home submitted that it had applied for the special DSU in order to remove any question of an off-target penalty being applied to the 4-9 well. It said that the well would be more than capable of draining the reserves underlying sections 8 and 9-97-11 W6M; therefore, the recovery of reserves underlying the two sections would not be adversely affected by approval of the special DSU. Furthermore, the special DSU would be an economically efficient means of development, as another well in section 8-97-11 W6M with associated facilities and costs would not be required to recover the gas involved. The applicant also submitted that equity within sections 8 and 9-97-11 W6M is not an issue, as the two sections are of common ownership. Finally, because the 4-9 well is on target to the south, the correlative rights of mineral holders to the south of the proposed special DSU would not be affected by the DSU. The applicant concluded that the application for a special DSU meets all of the criteria for such applications and should accordingly be approved.

The applicant requested that the order establishing the special DSU be effective as of 31 October 1990, the date of the application, in a manner consistent with its requests respecting the effective date of the orders issued as a result of Applications 901851 and 901852.

6.2 Views of the Interveners

Gulf supported the application for a special DSU. In its view, there are gas reserves underlying the target areas of sections 8 and 9-97-11 W6M, and a successful on-target well with a higher hydrocarbon pore volume than the 4-9 well could have been drilled on either section. Gulf also supported the application on the basis that, without the special DSU, it would have no definite knowledge that the required application for the continuation of the mineral lease for section 8-97-11 W6M would be successful.

Shell and Encor opposed the Home application for a special DSU on the basis that the applicant has not demonstrated that a well equivalent to the 4-9 well could have been drilled on target in section 9-97-11 W6M. In addition, Shell and Encor, together with Husky, expressed the concern that the special DSU would be used in a formula for distributing production from the A Pool, thereby adversely affecting the interveners' opportunity to recover an equitable share of gas from the pool. Shell and Encor indicated, however, that if the allocation of production were based on mapped reserves, they would have minimal concerns respecting the special DSU. Husky argued that it would be a contradiction for the Board to grant a two-section DSU when Home has requested an allocation of production in the A Pool based on single-section validation.

Columbia and Voyager et al did not specifically comment on the application for a special DSU.

6.3 Views of the Board

In this case, the Board considers that the matters relevant to establishing the requested special DSU would be

- whether the proposed special spacing would adversely affect the recovery of gas from the A Pool,
- whether the proposed special spacing would represent an economic and efficient use of resources, and
- whether the special spacing would have any unacceptable effects on another party's opportunity to recover its share of gas from the A Pool.

The Board believes that the evidence submitted indicates that the 4-9 well could effectively drain the existing reserves underlying sections 8 and 9-97-11 W6M and that the special DSU would represent an economic and efficient means of development. The Board notes that the 4-9 well is on target to the south and does not encroach on the proposed unit lands. The Board is therefore prepared to approve the application to establish the special DSU.

To be consistent with the orders respecting common processor and the distribution of production, the Board will issue the order establishing the special DSU on the date of this report.

7 NEED FOR PERMITS TO CONSTRUCT PIPELINES

7.1 Views of the Applicant

Home submitted that it would need to construct the two pipelines involved to allow competitive production of the 4-9 well if negotiations to expand the proposed unit to include the well failed.

7.2 Views of the Interveners

Gulf and Shell submitted that the two pipeline applications should be approved to allow competitive production from the 4-9 well if the proposed unit is not enlarged to include the well. Shell further indicated that even if unitization proceeds, approval of the applications could allow the tie-in of the 4-9 well in future to maintain deliveries to the gas plant. Encor acknowledged the potential need for the permits to construct the pipelines to allow competitive production of the 4-9 well if unitization failed; however, it was of the opinion that the issuance of an order distributing production from the A Pool would lead to the expansion of the proposed unit, thereby rendering the proposed pipelines unnecessary. Columbia, Husky, and Voyager et al did not comment on the pipeline applications.

7.3 Views of the Board

The Board agrees with the views expressed that if unitization does not proceed, Home and Gulf will require the proposed pipelines to allow competitive production of the 4-9 well. Further, the Board is satisfied that the applicant has appropriately dealt with the route of the proposed pipelines and other matters relating to the construction of the pipelines. The Board notes that these matters were not identified as areas of concern by any intervener. The Board is therefore prepared to approve the two pipeline applications.

8 DECISION

For the reasons noted above, the Board

- approves Application 901851, subject to the authorization of the Lieutenant Governor in Council, for an order declaring Shell Canada Limited as a common processor of natural gas and natural gas liquids produced from the Hamburg Slave Point A Pool, effective the date of this report,

- approves Application 901852, for an order distributing production from the Hamburg Slave Point A Pool in the manner set out in Section 5.8 of this report, effective the date of this report,

- approves Application 901853, for an order establishing sections 8 and 9 of township 97, range 11, west of the 6th meridian, as a special drilling spacing unit, with the target area being within the drilling spacing unit and having sides 300 metres from and parallel to the sides of the drilling spacing unit, for the production of gas from the Slave Point Formation, effective the date of this report, and

- approves Applications 910048 and 910049, for approvals to construct sweet natural gas and fuel gas pipelines, effective the date of issuance of the approvals.

The Board is prepared to rescind the common processor order on receipt of an uncontested request from an interested party.

DATED at Calgary, Alberta, on 26 June 1991.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

Langlo

C. A. Langlo, P.Geol.
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Columbia Gas Development of Canada Ltd. (Columbia) D. G. Guest	C. Bengtson G. W. Blanchard, P.Eng.
Encor Energy Corporation Inc. (Encor) A. L. McLarty G. E. Waskiewich	J. P. Andersen, P.Geol. M. B. Gough, P.Eng. J. A. Henry, P.Eng. L. Mattar, P.Eng. of Fekete Associates Inc. I. F. Smith, P.Geol. P. Vodak
Gulf Canada Resources Limited (Gulf) G. B. Scott	O. G. Burrows L. W. Freeman, P.Eng. A. C. Gringarten of Scientific Software-Intercomp Inc. R. W. Hausegger B. L. Illing, P.Geol. C. Juergens D. J. Lovitt, P.Eng.
Home Oil Company Limited and Scurry-Rainbow Oil Limited (Scurry) (collectively referenced as Home) D. G. Hart P.W.M. Read, P.Eng.	R. B. Banderk, P.Eng. D. S. Bartsch, P.Geoph. L. B. Caine, M.B.A. J. D. Reimer, P.Geol. D. H. Smith, P.Eng. P. D. Trowell, P.Geol.
Husky Oil Operations Ltd. (Husky) S. M. Purcell	M. I. Azzam S. Chugh, P.Eng.
Shell Canada Limited (Shell) E. S. Decter	C. P. Barry, P.Geoph. R. J. Daeninck, P.Eng. T. T. Dziuba D. J. Hemphill, P.Eng. R. W. Willoughby, P.Eng.

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Voyager Energy Inc. (Voyager) and Excel Energy Inc. (collectively referenced as Voyager et al) R. E. Chillack	R. W. Hoover, P.Eng.
Energy Resources Conservation Board staff D. B. Fairgrieve, P.Geol. K. Fisher H. R. Keushnig, P.Eng. A. L. Larson, P.Eng. M. Pinney T. K. Wong, P.Geol.	

TABLE 2 WELLBORE RESERVOIR PARAMETRES FOR WELLS IN THE HAMBURG SLAVE POINT A POOL

Well	Validated Area (hectares)	Net Pay (metres)					Porosity (per cent)					Water Saturation (per cent)					Hydrocarbon Pore Volume [a]				
	Board	Home	Gulf	Shell	Encor	Board	Home	Gulf	Shell	Encor	Board	Home	Gulf	Shell	Encor	Board	Home	Gulf	Shell	Encor	Board
2/10-29	1036	20.4	19.0	23.62	19.2	20.1	10.6	13.5	11.7	11.4	12.9	6.8	6.0	6.0	7.8	8.3	2.02	2.41	2.60	2.02	2.37
3-33	518	20.8	15.1	21.90	22.2	23.4	6.2	8.5	6.6	6.5	8.0	19.9	19.0	19.0	22.3	19.0	1.03	1.04	1.17	1.13	1.52
12-26	518	7.9	7.3	8.10	9.6	7.8	8.4	11.0	11.7	10.5	11.7	23.0	19.0	19.0	23.9	17.3	0.51	0.65	0.77	0.77	0.75
13-35	777	7.0	6.5	6.30	6.6	7.1	13.0	13.0	13.2	12.6	13.0	10.2	11.0	13.0	13.1	15.0	0.82	0.76	0.72	0.72	0.78
2-6	518	22.2	21.8	18.00	24.4	22.8	11.0	12.4	11.3	11.0	10.8	5.3	8.0	9.0	6.1	7.8	2.31	2.48	1.85	2.53	2.27
4-9	259	18.8	19.0	17.20	17.8	19.5	12.3	11.0	9.7	9.4	9.9	5.4	10.0	7.0	8.9	8.2	2.18	1.90	1.55	1.54	1.77

[a] Hydrocarbon Pore Volume = Net Pay (metres) x Porosity (fraction) x (1 - Water Saturation (fraction))

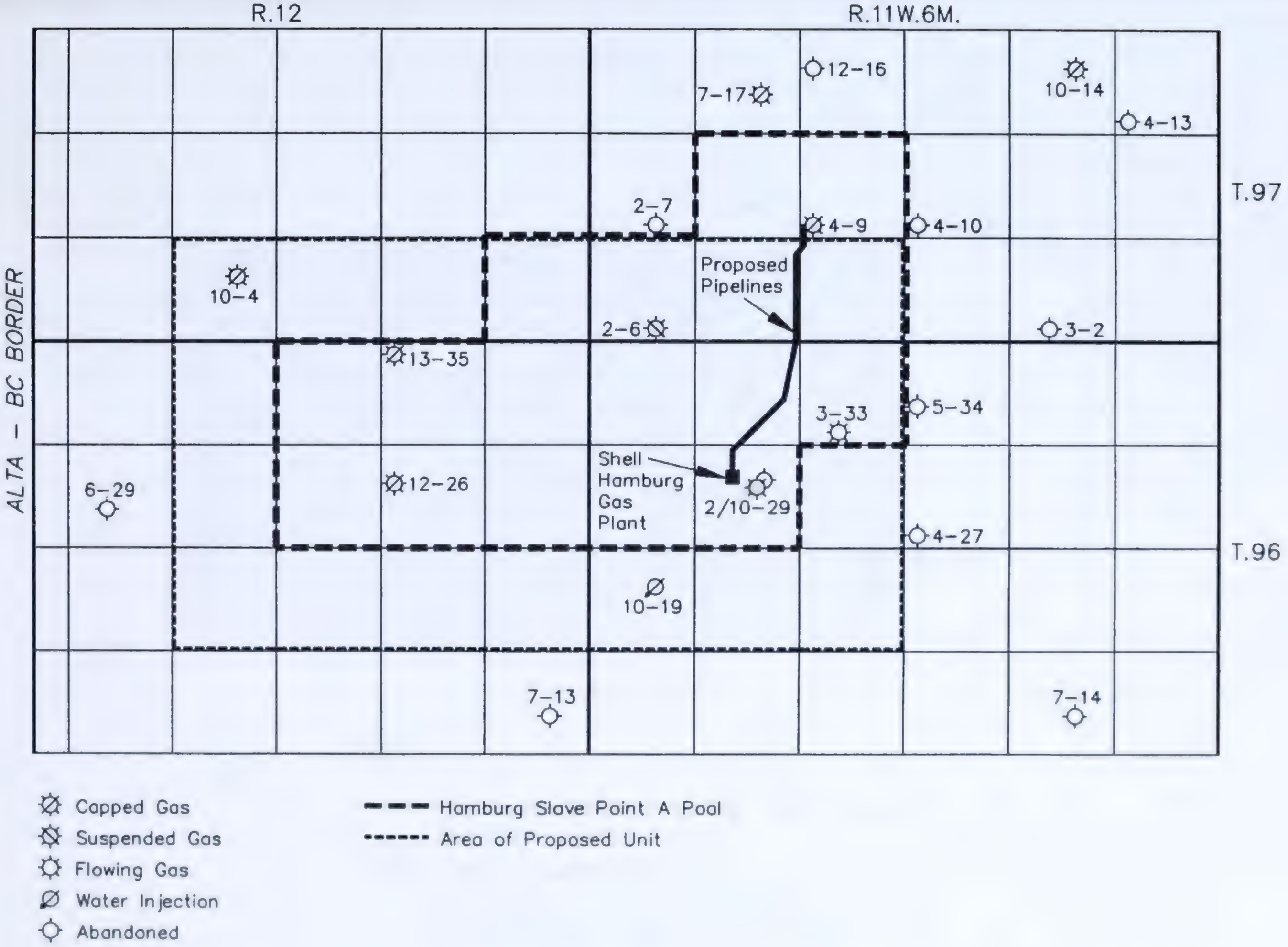
TABLE 3 ALLOCATION FORMULA AND RESERVES - BASED ALLOCATIONS FOR THE HAMBURG SLAVE POINT A POOL

	Per Cent of Production Allocated on Basis of					
	Mapped Reserves[a]		Single-Section Validation[b]		Multiple-Section Validation (As Discussed In Report)[b]	
	Secs 8&9-97-11 W6M	Proposed Unit	4-9 Well	Proposed Unit Wells	All/Portion Secs 8&9-97-11 W6M	Validated Proposed Unit Area
Home	11.7	—	24.6	75.4	19.3 (all of secs 8&9-97-11 W6M validated)	80.7
Gulf	14.6	85.4	20.6	79.4	15.8 (all of secs 8&9-97-11 W6M validated)	84.2
Shell	2.1	97.9	17.9	82.1	7.1 (south halves of secs 8&9-97-11 W6M validated)	92.9
Encor	2.46	97.54	17.7	82.3	---	---
Husky	2 to 13	87 to 98	---	---	---	---
Board	---	---	---	---	7.8 (south halves of secs 8&9-97-11 W6M validated)	92.2

a As discussed in report

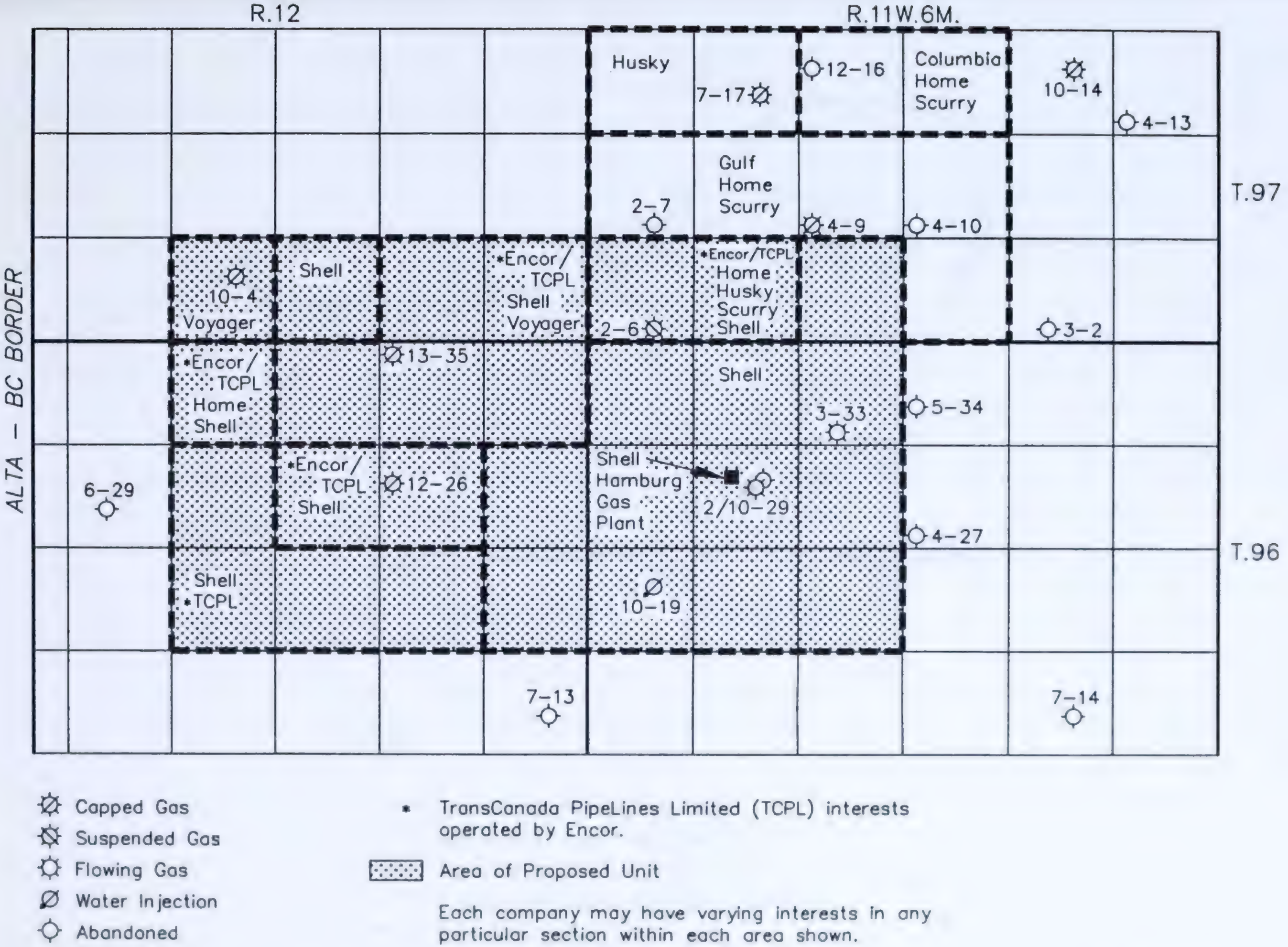
b As calculated using values set out in report and the formula noted below:

$$\text{Per Cent of Pool Production for Single- or Multiple Section Validated Areas} = \frac{\text{Hydrocarbon Pore Volume (from Table 2) x Validated Area (as discussed in report) For Well(s)/Area(s) of Interest}}{\text{Sum of (Hydrocarbon Pore Volume x Validated Area) for All Wells}} \times 100$$



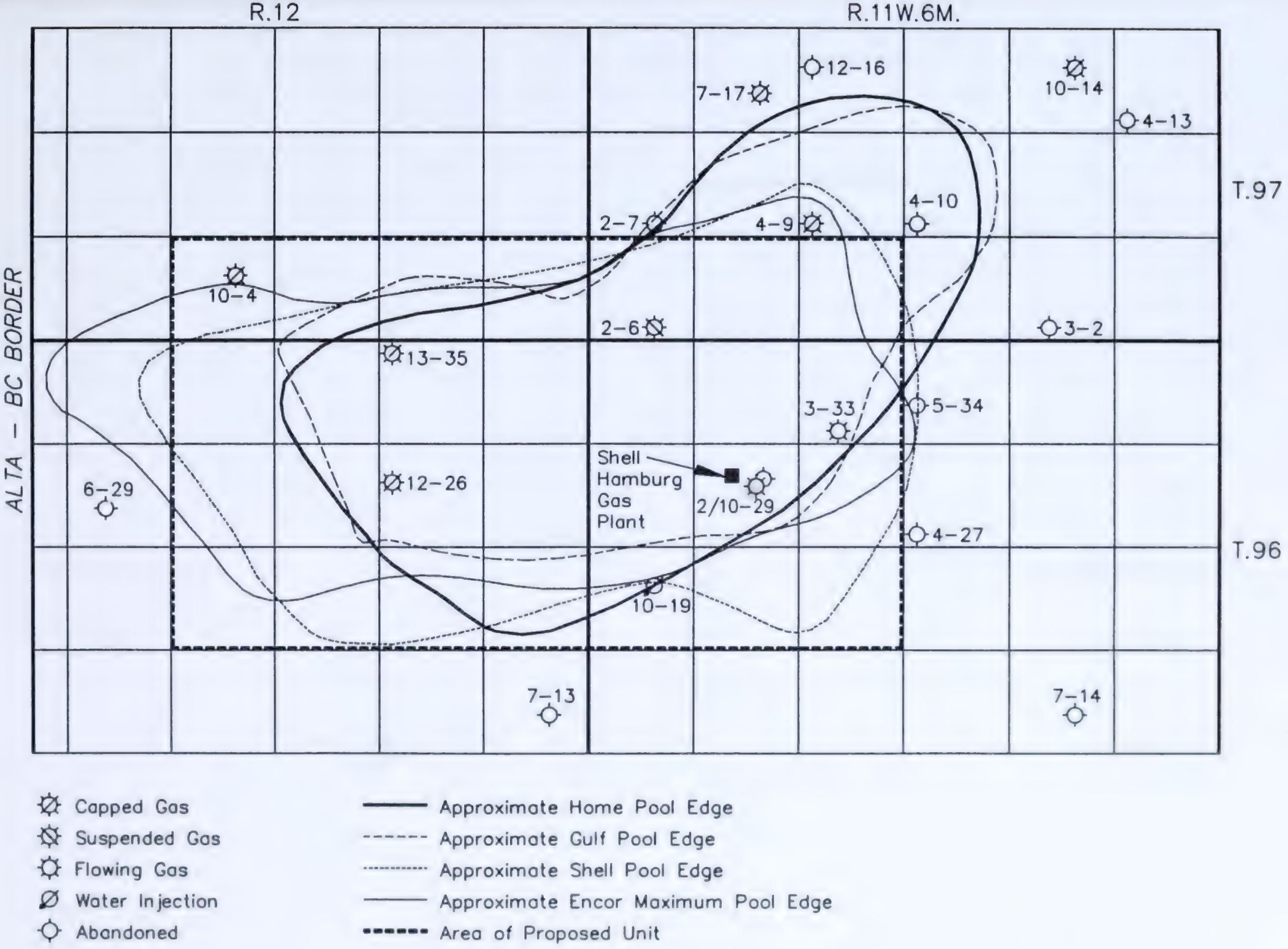
Note: Map shows only those wells which have penetrated the Slave Point Formation.

FIGURE 1 HAMBURG AREA OVERVIEW



Note: Map shows only those wells which have penetrated the Slave Point Formation.

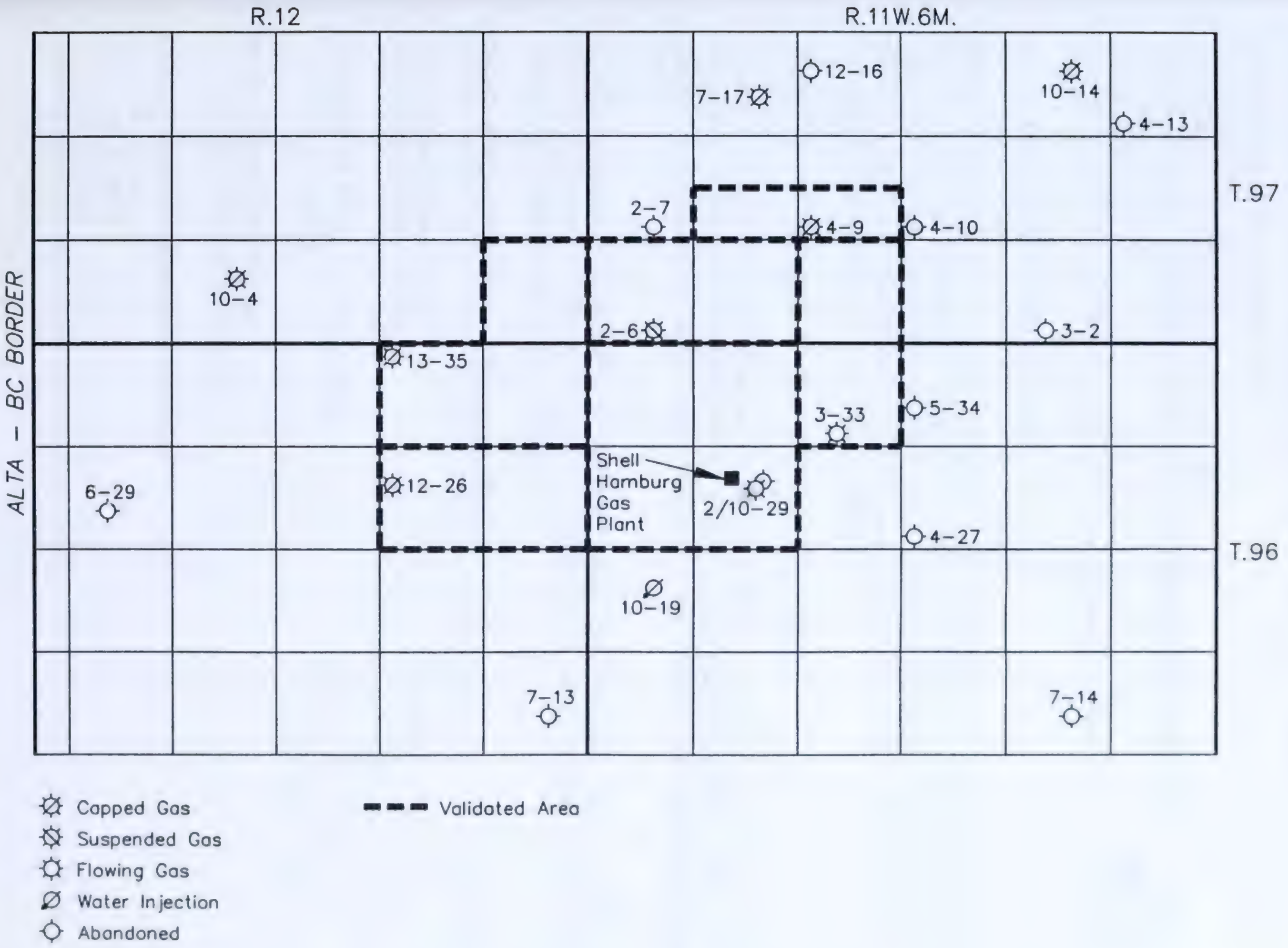
FIGURE 2 MINERAL INTERESTS IN GENERAL AREA OF APPLICATION



Note: Map shows only those wells which have penetrated the Slave Point Formation.

FIGURE 3 HEARING PARTICIPANTS' INTERPRETATIONS OF THE HAMBURG SLAVE POINT A POOL

D 91-8



Note: Map shows only those wells which have penetrated the Slave Point Formation.

FIGURE 4 VALIDATED AREAS USED IN ALLOCATION FORMULA

D 91–8

ERCB

ENERGY RESOURCES CONSERVATION BOARD

STRATHFIELD OIL & GAS LTD.
APPLICATIONS FOR
– A PERMIT TO CONSTRUCT A PIPELINE
– APPROVAL TO CONSTRUCT A SATELLITE PRODUCTION FACILITY
– A WELL LICENCE
PROVOST FIELD

Decision D 91-9
Applications 910284,
910314, and 910597

1 APPLICATION AND HEARING

Strathfield Oil & Gas Ltd. (Strathfield) applied to the Energy Resources Conservation Board (the Board) for approval to construct a pipeline to transport oil-well effluent from wells located in Lsd 13-23-37-4W4M and Lsd 5-26-37-4W4M to an existing pipeline located in Lsd 4-26-37-4W4M, to construct a satellite production facility to be located at Lsd 4-26-37-4W4M, and for a licence to drill a well from a surface location in Lsd 13-23-37-4W4M.

The applications were opposed by Mr. R. Hanson (Mr. Hanson).

A public hearing of the applications was originally scheduled to commence on 30 April 1991. Mr. Hanson requested a postponement of the hearing in order that he be given sufficient time to prepare for the hearing and obtain witnesses to speak to his concerns. The request was granted by the Board.

A public hearing of the applications was held on 11 June 1991 in Provost, Alberta, before a division of the Board comprised of Board Members J. P. Prince, Ph.D. and B. F. Bietz, Ph.D., P.Biol., and Acting Board Member J. D. Dilay, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Strathfield Oil & Gas Ltd. (Strathfield) R. A. Neufeld	L. G. Smith, P.Eng. K. R. MacLellan, P.Eng.
Mr. R. Hanson (Mr. Hanson) J. W. Bodnar (Mr. Bodnar)	
Energy Resources Conservation Board staff B. Boyd M. J. Bruni N. F. Lord	

2 PRELIMINARY MATTERS

At the outset of the hearing, Mr. Bodnar, counsel for Mr. Hanson, submitted that Mr. Hanson would not be appearing at the hearing nor participating in the proceedings with formal evidence or cross-examination. Mr. Bodnar had, however, been instructed to set out the reasons why Mr. Hanson would not be participating and his views on the Board's procedures with respect to the applications. Mr. Hanson submitted that it was not in the best interest of agriculture and the environment for the hearing to proceed and for the applications to be approved. Mr. Hanson questioned the applicant's and the Board's qualifications to address matters of impact on agriculture and the environment. Mr. Hanson further questioned the Board's jurisdiction and mandate where matters of agriculture and the environment were involved. He therefore requested that the hearing be postponed until such time as he could be satisfied that matters pertaining to agriculture and the environment would be addressed properly in the consideration of the applications.

Strathfield submitted that it believed the Board did have the jurisdiction and mandate to consider the applications and matters pertaining to them and that the Board could either approve or deny any such applications. Strathfield noted that the matter of the well licence had already received consideration environmental consideration in the Board's Decision D 89-8. The Board in that decision concluded that a conventional straight hole proposed to be drilled in Lsd 13 would not be consistent with the concept of reducing environmental impacts in sensitive areas through the consolidation of wells into multi-well pads.

The Board believes that the mandate and jurisdiction of the Board are clearly set out under the Oil and Gas Conservation Act and the Energy Resources Conservation Act . The Board is of the view that it has the jurisdiction and mandate to consider all applications with respect to a range of issues, including potential impacts on agricultural activities and the environment.

The Board denied Mr. Hanson's request that the hearing be postponed.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Strathfield

Strathfield submitted that it believed the applications were consistent with the intent and direction of the Board's Decision D 89-8 and would not result in further impacts on agriculture or the environment in the region. The construction of the pipeline would aid in consolidating operations. The satellite facility would be a closed system serving a number of wells. The proposed well would be directionally drilled and consistent with the concept of the development of multi-well pads as an alternative to conventional single-well sites.

Strathfield stated that as an operator it was attempting to implement measures and participate in activities designed to reduce adverse impacts on agricultural activities and the environment in the Provost area. Strathfield believed that these efforts have been successful and that improvements in general operational activities and impacts have been made.

3.2 Views of the Board

The Board notes that no specific evidence in opposition to the applications was presented at the hearing for the Board's consideration. In this light and considering that the applications meet all of the Board's requirements and that there is a need for the requested facilities, the Board believes the applications should be approved. The Board notes that any licence and/or approval issued would be subject to standard conditions designed to reduce negative impacts on agriculture and the environment and that operations would be expected to be carried out in a manner consistent with good oil field practices in the area.

4 DECISION

The Board approves Applications 910284, 910314, and 910597. The appropriate documents will be issued in due course.

DATED at Calgary, Alberta, on 13 June 1991.

ENERGY RESOURCES CONSERVATION BOARD

J.P. Prince

J. P. Prince, Ph.D.
Acting Co Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

J Dilay

J. D. Dilay, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

NORCEN ENERGY RESOURCES LIMITED
APPLICATION FOR A WELL LICENCE
PROVOST FIELD

Decision D 91-10
Application 910777

1 INTRODUCTION

1.1 Application and Interventions

Norcen Energy Resources Limited (Norcen) applied to the Energy Resources Conservation Board (the Board), pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the regulations), for a licence to drill a well from a surface location in legal subdivision 6 of section 32, township 38, range 3, west of the 4th meridian (the proposed surface location) to a bottom-hole location in legal subdivision 15 of section 32, township 38, range 3, west of the 4th meridian (the proposed bottom hole location). The purpose of the well would be to obtain oil production from the Lloydminster Formation.

On 15 May 1991, the Board issued well Licence Number 148872 for the proposed well.

Interventions opposing the well licence and a request for a review of the licence were filed by Mrs. Elizabeth Guenthner, the surface owner of the northwest quarter of section 32, township 38, range 3, west of the 4th meridian (NW 1/4 Sec 32), and Mrs. Sherry Musak, the occupant of a house located on the quarter. The interventions were based on the potential for dust problems, noise impacts, water well damage, and the safety of Mrs. Musak's family.

1.2 Hearing

A public hearing to review the application was originally scheduled for 13 June 1991. Prior to that date, the Board received requests from the interveners for a postponement of the hearing. The Board rescheduled the hearing for 24 June 1991.

The public hearing to review the application was conducted at Provost, Alberta, before F. J. Mink, P.Eng., C. A. Langlo, P.Geol., and W. G. Remmer, P.Eng. At the outset of the hearing Mr. W. P. Nelson (Mr. Nelson) stated that owing to unforseen circumstances, Mrs. Guenthner and Mrs. Musak could not appear at the hearing and that he had been appointed by them to represent their views and positions in their absence. Following the hearing a site visit was conducted. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Norcen Energy Resources Limited (Norcen) B. W. Jenson	B. W. Jenson, P.Eng. L. S. Uhrich, P.Eng. W. J. Spark, P.Eng. P. R. Brady
W. P. Nelson (Mr. Nelson) W. P. Nelson	D. Dzurko W. P. Nelson
Energy Resources Conservation Board staff C. S. Richardson	

2 ISSUES

The Board considers the issues with respect to this review to be

- the need for the well,
- the surface location of the well and access road, and
- impacts of the well and access road.

3 NEED FOR THE WELL

Norcen submitted that it held petroleum and natural gas lease number 31775 from the Province of Alberta and, as such, it had the right to produce oil and gas from the Lloydminster Formation in section 32. It stated that the well was needed in order to prove up the minerals.

The interveners did not dispute the need for the well and stated that the intervention was not intended to deny Norcen its rights to its minerals.

The Board notes that Norcen's geologic interpretation was not disputed and that the interveners did not challenge the need for the well. The Board believes that Norcen should be provided the opportunity to explore for its minerals, unless that exploration would be contrary to the public interest.

4 SURFACE LOCATION OF THE WELL AND ACCESS ROAD

Norcen stated that it had originally planned to directionally drill a well to a bottom-hole location in legal subdivision 11 of section 32 (the 11-32 well) from a surface location in legal subdivision 11 of section 32 (the 11-32 surface location). It had approached Mrs. Guenthner in order to secure a surface lease for the well but was unable to obtain her consent. Norcen re-evaluated the selection of the surface location taking into account all aspects related to reservoir performance, production operations and surface intrusion and determined that the preferred surface location would be from Lsd 6-32. Norcen stated that because the well would have a horizontal segment through the producing zone, the surface location should have a horizontal displacement of approximately 450 metres (m) from the beginning of the horizontal leg of the well in order to accommodate the turning radius of the wellbore. Although the proposed surface location resulted in slightly higher drilling costs than the 11-32 surface location, it believed that this was offset by a reduction of surface impacts. The 6-32 surface location would allow Norcen to utilize the existing lease area, existing access from the municipal road allowance and existing pipeline, for production to its battery (see figure). Norcen approached Mr. Maurice O'Callaghan the surface owner of the southwest quarter of section 32 (SW 1/4 Sec 32), and secured a surface lease agreement and his approval to use the existing access easement.

Norcen submitted that it had considered alternative locations for the access road in response to concerns raised by the interveners. It discounted these alternatives due to the considerable construction and road build up required to maintain a solid road base across low areas. It was Norcen's preference to minimize land disturbance by utilizing the existing 6-32 access road. Although the existing access road has not been used for several years and is currently under cultivation, Norcen stated that it would prefer not to upgrade the access road since reclamation would be more difficult from a built-up roadway, particularly if it were oiled. Norcen also stated it was the landowner's preference that he be allowed to cultivate over the access road.

Mr. Nelson stated that the proposed access road location is a poor choice because of the impacts it would cause to Mrs. Musak and her family. He submitted that an access road entering the proposed well location from the north, along the east boundary of NW 1/4 Sec 32, would move the impacts away from the Musaks. Mr. Nelson believed that an access road should be properly constructed using suitable gravel in order to minimize damage to the topsoil and reduce soil erosion, by oiling the road surface. This type of roadway would also require less maintenance during severe winter weather when snow may cause problems. He also submitted that the existing 6-32 access road has not been used by Norcen for several years as the 6-32 well has been suspended. The interveners believed that Norcen's decision to use the proposed access was an economic decision rather than one based on minimizing land disturbance. They stated that Norcen had not fully considered other alternative road locations.

The interveners did not contest the proposed surface location for the well, but had concerns over how the well would be drilled and operated. They stated that the breakdown in negotiations over the original 11-32 well location was due to failure to agree on compensation and details of the surface lease, but was not a refusal by the interveners for the well location. The interveners recognized that the original 11-32 access road would be closer to the Musak's residence than the proposed well location, but believed that with certain conditions in place on how the drilling and operation of the well would proceed, the impacts would be minimal. The interveners believed that Norcen's proposed well location would create unacceptable noise and potential water well damage.

To assess the appropriateness of the well and access road location, the Board considered how the interveners would be affected and what mitigative measures, if any, are available to reduce any impacts to an acceptable level. The Board notes that the interveners were agreeable to the original 11-32 surface location and that the proposed location would be farther from the Musak's residence. The proposed site would also minimize land disturbance since it uses an existing well site.

With respect to the access road location, the Board agrees with Norcen that utilizing existing access is preferable to creating new surface disturbance, provided that the use of that location does not create unacceptable impacts. However, the present road access has been cultivated and was difficult to detect. The Board notes that road construction from the north or east of the proposed well location could involve greater land disturbance than utilizing the existing access. The Board also notes that Norcen would not upgrade the existing access, but would allow the surface owner to cultivate the road as much as possible.

5 IMPACTS OF THE WELL AND ACCESS ROAD

Norcen submitted that the proposed well location would pose little impact on the interveners. It stated that the well would be drilled in approximately 12 to 14 days. During the drilling phase there would be several vehicles, including heavy trucks that would travel to and from the well site. Norcen stated that it would control dust during the drilling phase by keeping the full length of the access road and the municipal road wet in the vicinity of the Musak's residence. If soil conditions at the proposed location were such that an on lease sump would not contain the drilling fluids, it would utilize a plastic sump liner or steel tanks and a remote sump. Norcen proposed to set and cement surface casing to a depth of 130 m. It believed that its proposed casing and cementing program would provide well control and would ensure protection of any surface water or potable aquifers. It further agreed to test the water well at the Musak's residence before and after drilling, for water quality and flow rate.

With respect to safety concerns by the interveners, Norcen stated that it had installed a snow fence along the north side of the access road for a distance of approximately 400 m in order to prevent the Musak's children and pets from wandering onto the access road. It intended on removing the snow fence after drilling operations.

Norcen proposed several mitigative measures to address long-term impacts from the well. It would tie in the proposed well to the existing pipeline at the 6-32 location which would eliminate any flaring and need to use tank trucks to haul oil. It believed this would greatly reduce potential odours, emissions, and dust problems. There would be one pick-up truck per day driven to the well site by Norcen's operator, a one-ton maintenance truck bimonthly, and a service rig and other heavy equipment approximately once per year for a 2- to 3-day period. Norcen believed that the minimal use of the access road during the production phases of the well would not cause any undue dust problems. To prevent unauthorized entry into the well site, Norcen would be prepared to install a locked gate at the access road approach to the municipal road allowance subject to the surface owner's approval.

The interveners raised a number of concerns about the proposed access road during the drilling and production phase of the 6-32 site. They contended that the impacts from the proposed well site and access road would be unacceptable. They stated that there are no assurances that groundwater or potable aquifers could be protected and cited examples where water well quality and quantity had deteriorated in the presence of nearby oil well drilling activity. They argued that the surface casing setting depth for the proposed well would not protect deeper Belly River aquifers and believed that a poor cementing job in the proposed well could allow migration of gas from deeper zones into potable aquifers.

The interveners were also concerned that vehicle traffic during drilling and production operations would pose a safety hazard for small children and would cause an unacceptable dust problem. They did not believe that the snow fence provides adequate precaution to prevent children or pets from wandering onto the access road because the fence is open at both ends. They submitted that when the 6-32 well was on production from 1983 to 1985 the excessive traffic levels caused severe noise and dust problems, and that if the proposed well were approved, these problems would recur. The interveners did not believe that a locked gate would be an effective means of controlling unauthorized access as there is no fence on the west boundary of the section. They stated that noise from the proposed gas-powered pump motor would be heard at the Musak's residence and suggested that the pump should be powered by electricity. The interveners submitted that the only effective way to minimize impacts would be to require Norcen to relocate the access road to their proposed route or to a route from the east side of the 6-32 location.

The Board has carefully considered the potential impacts from the proposed well site and access road. With regard to drilling the Board notes that the well is expected to be completed within approximately 14 days and therefore believes that any impacts from drilling operations would be temporary in nature. It also notes that the proposed well location is approximately 700 m from the Musak's residence and is screened by a shelter belt of trees on the east side. The Board would see benefit in housing the pump and motor and ensuring that proper mufflers be installed. The Board believes that any noise from the pump motor would not be excessive. It also believes that impacts from the proposed well site would be minimal considering Norcen's plans to immediately tie the well into the existing pipeline, thus eliminating flaring, emissions, and trucking of oil from the location.

With respect to potential safety hazards from the access road, the Board concurs with Norcen that a barrier adjacent to the Musak's residence such as the snow fence is a prudent measure and given the length of installation should limit the access of small children on the road. Visibility through the fence appears to be adequate to allow truck drivers to detect movement. The Board believes that the municipal road represents a greater enduring safety factor and that the access road would not significantly increase the risk to the Musak family. Although the Board does not expect the proposed access road to the well site to present an inordinate safety hazard, it will require Norcen to instruct all rig and operations personnel to drive with caution in the vicinity of the residence. The Board also sees merit in Norcen's suggestion that signs be placed at appropriate locations that would restrict Norcen personnel to an appropriate speed.

Regarding unauthorized use of the access road the Board believes that a locked gate as suggested by Norcen would act as a deterrent to entry onto the road. The Board would also see merit in a sign installed at the gate that would stipulate no unauthorized use of the access road.

Given the state of the existing range trail, the Board expects the prospect for dust during drilling operations will be significant. Accordingly, the Board will require Norcen to maintain wet conditions on the full length of the access road and the municipal road in the vicinity of the Musak's residence during drilling operations. The Board disagrees with Norcen, that dust would not be a problem during ongoing servicing and maintenance of the well. Although travel to the well by the operator once per day in a pick-up truck would likely not cause a serious dust problem. The Board believes it would be appropriate that if ground and moisture conditions require it, Norcen should water the access road during servicing and maintenance operations to control dust.

With respect to protection of groundwater and aquifers, the Board finds Norcen's proposed casing and cementing program to be consistent with the regulations. Although it is generally recognized that Norcen would be held accountable for any disturbance to water wells caused by its operations, the Board agrees that testing the Musak's water well for quality and flow rate would be a good precautionary measure. The Board expects that a gasification test of the water before and after the drilling should also be carried out. Further, if representative gas samples are present in the water, a gas composition analysis should be conducted. The Board believes that if the intrusion of gas into the water well aquifer occurs, it could be more easily detected by first compiling baseline flow, quality and gasification data.

6 DECISION

The Board has carefully reviewed the issues respecting the well licence, proposed well location, as well as the views and concerns of Norcen and the interveners. The Board believes there is a need for the well and drilling operations could proceed subject to the following conditions:

- Norcen shall approach Mr. O'Callaghan respecting a locked gate at the approach to the municipal road from the access road,
- a sign shall be installed at the approach to the municipal road that stipulates no unauthorized use of the access road,
- Norcen shall consult with the interveners regarding a water quality, flow rate, and gasification test of the interveners' water well, and include a gas analysis to show if gas is present in measurable quantities,
- Norcen shall keep the full length of the access road and the municipal road in the vicinity of the Musak's residence wet during drilling operations and during servicing and maintenance operations if ground conditions dictate,
- Norcen shall endeavour to conduct its operations cautiously and maintain vehicles at an appropriate speed when in the vicinity of the Musak's.

Well Licence Number 148872 remains in good standing.

DATED at Calgary, Alberta on 22 July 1991.

ENERGY RESOURCES CONSERVATION BOARD

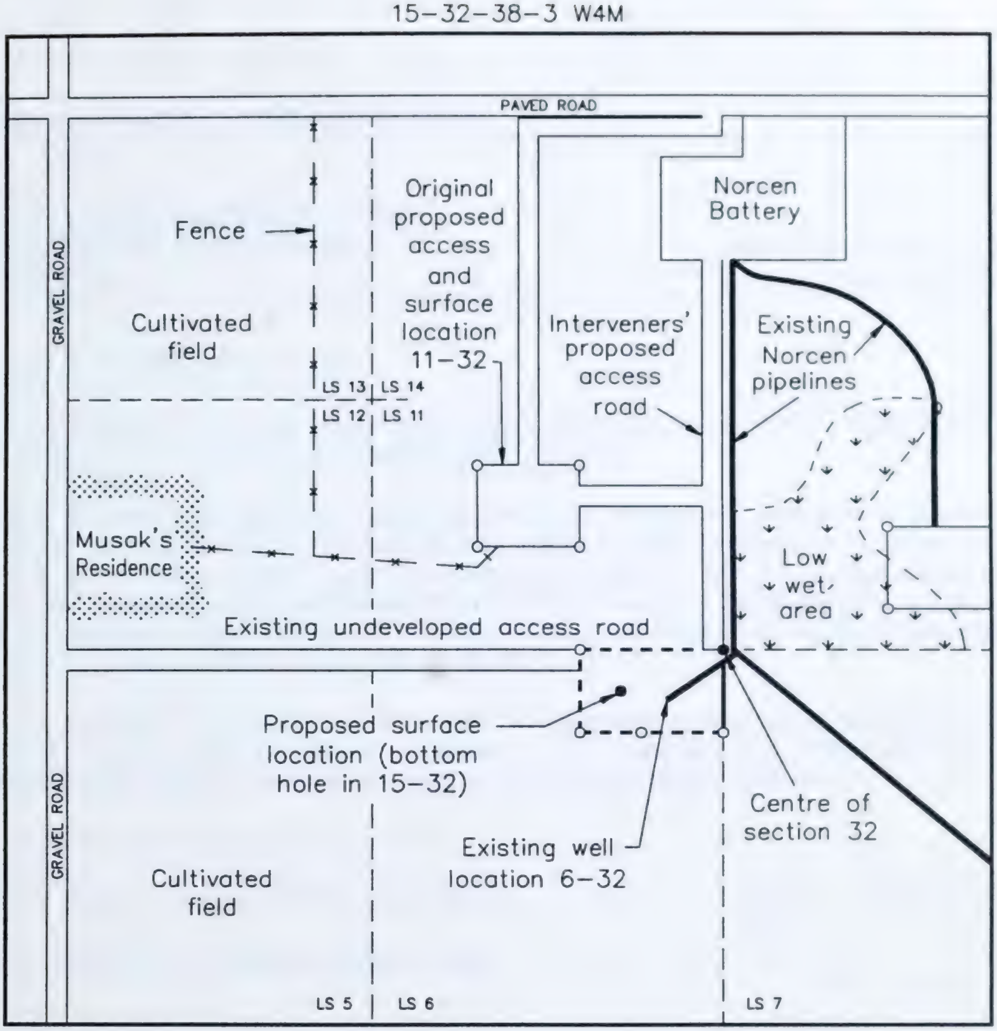
F. J. Mink, P.Eng.*
Vice Chairman

Langlo
C. A. Langlo, P.Geol.
Acting Board Member

W. G. Remmer, P.Eng.*
Acting Board Member

---

* Mr. Mink and Mr. Remmer were unavailable for signature but concur with the contents and with the issuing of this report.


15-32-38-3 W4M
PAVED ROAD
GRAVEL ROAD
Fence
Cultivated field
Original proposed access and surface location 11-32
Norcen Battery
Interveners' proposed access road
Existing Norcen pipelines
LS 13
LS 14
LS 12
LS 11
Low wet area
Musak's Residence
Existing undeveloped access road
Proposed surface location (bottom hole in 15-32)
Centre of section 32
Existing well location 6-32
GRAVEL ROAD
Cultivated field
LS 5
LS 6
LS 7

PROPOSED WELL LOCATION
APPLICATION NO. 910777
NORCEN ET AL PROVOST 15-32-38-3

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

NORCEN ENERGY RESOURCES LIMITED
APPLICATION FOR A WELL LICENCE
PROVOST FIELD

Addendum to Decision D 91-10
Application 910777

ADDENDUM TO DECISION D 91-10

The Energy Resources Conservation Board issued Decision D 91-10 on 22 July 1991. Upon further review of the report the Board has identified two minor corrections.

On page 2, Section 4 of the report, the existing statement reads "Norcen stated that it had originally planned to directionally drill the well to a bottom-hole location in legal subdivision 11 of section 32 (the 11-32 well) from a surface location in legal subdivision 11 of section 32 (the 11-32 surface location).". The corrected statement is "Norcen stated that it had originally planned to directionally drill a well to a bottom-hole location in legal subdivision 16 of section 32 (the 16-32 well) from a surface location in legal subdivision 11 of section 32 (the 11-32 surface location).".

On page 3, paragraph 4, the existing statement reads "The interveners recognized that the original 11-32 access road would be closer to the Musak's residence...". The correct statement is "The interveners recognized that the original 11-32 well site would be closer to the Musak's residence...".

The corrections have no impact on the decision.

DATED at Calgary, Alberta on 21 November 1991.

ENERGY RESOURCES CONSERVATION BOARD

RECEIVED
JAN - 9 1992

F. J. Mink, P.Eng.
Vice Chairman

C. A. Langlo, P.Geol.
Acting Board Member

W. G. Remmer, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SEP 11 1991

TRANSALTA UTILITIES CORPORATION
138-kV TRANSMISSION LINE 848L
BENALTO–CAROLINE AREA

Decision D 91-11
Application 901415

1 INTRODUCTION

On 2 October 1990, TransAlta Utilities Corporation (TransAlta) applied, pursuant to sections 12 and 14 of the Hydro and Electric Energy Act, for approval to construct approximately 65 kilometres (km) of 138-kV transmission line designated as 848L from Benalto to the Caroline area and the related substation facilities required to connect and operate it. The proposed facilities would serve the recently approved Shell Caroline gas development project and other electric loads that are developing in the area.

The application was advertised for objection on 29 October 1990, with notice mailed to various parties who might be affected by the proposed line. The Board received two objections to the notice, which were subsequently resolved by the applicant. The Board completed its review of the application and granted it. The necessary permits and licences for the project were issued on 22 January 1991. In the absence of a hearing, the Board does not routinely notify parties affected by the granting of an application. In this case, however, it is the Board's understanding that a group of local landowners (Kujala Group) became aware on or about 5 February 1991 of the Board's approval of the application.

On 26 February 1991, a letter was received from the Kujala Group. The group expressed several concerns with a 12.8-km (8-mile) section of the approved transmission line route identified as ABC and suggested an alternative alignment identified as ADC, as shown on the attached figure.

After meeting with Board staff and the Kujala Group in March 1991, TransAlta indicated it would be prepared to amend its application to the Board to alter its line route if consent could be obtained from all affected landowners and residents along the alternative route suggested by the Kujala Group. After contacting the parties along the alternative route, TransAlta advised the Board and the Kujala Group, by letter dated 6 May 1991, that agreement could not be obtained from all affected landowners and residents along the alternative route. As a result, the Kujala Group, by letter to the Board dated 8 May 1991, requested that a hearing be convened to determine which route would be the most suitable.

2 NOTICE AND HEARING

In response to the Kujala Group letter of 8 May 1991, the Board, pursuant to section 43 of the Energy Resources Conservation Act, directed that a hearing be held in Innisfail. Notice of hearing was sent to all potentially affected parties along the entire approved route as well as all newly affected parties along the alternative route suggested by the Kujala Group. A submission was received from the Kujala Group regarding approved route ABC. No objections to the suggested alternative route ADC were submitted prior to the hearing.

The application was considered at a public hearing in Innisfail on 26 June 1991 with Dr. B. Bietz, P.Biol. (Chairman), M. J. Bruni, and C. A. Langlo, P.Geol. sitting. Those who attended the hearing are listed below.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
TransAlta Utilities Corporation (TransAlta) J. G. Friesen	M. J. Chorel, P.Eng. N. J. Brausen, P.Eng. J. C. Chalmers, C.E.T.
The Kujala Group G. Kujala	C. Hoven Mrs. L. Wyzykoski G. Kujala
Alberta Environment R. Grover	
Energy Resources Conservation Board staff R. D. Heggie R. L. Schroeder B. E. Olliver	

At the conclusion of the hearing the Board announced its decision, with reasons to follow, to grant the alternative alignment identified as ADC on the attached figure, and to issue the appropriate permit and licence upon receipt of Ministerial approvals from Alberta Environment and Alberta Forestry, Lands and Wildlife. This report will provide the Board's reasons for the decision.

3 PRELIMINARY MATTERS

In its submission to the Board, dated 19 June 1991, TransAlta objected to the holding of a hearing on the basis that the Kujala Group did not apply for a hearing within the 30-day period required pursuant to section 43 of the Energy Resources Conservation Act. Alternatively, TransAlta stated that, if the Board determined that the hearing should proceed, the Kujala Group should be considered the applicant under section 43 and, accordingly, should lead evidence first. The Kujala Group did not comment on these matters at the hearing.

Although the Board notes that TransAlta waived their procedural objections at the outset of the hearing, the Board is prepared to provide the following comments on these issues.

Firstly, with respect to the 30-day filing period provided for in section 43 of the Energy Resources Conservation Act, the Board is of the view that the Kujala Group filed an objection within the 30-day time period. In this case, TransAlta's application was granted and the permits and licences related thereto were issued on 22 January 1991. As stated earlier the Board's understanding is that the Kujala Group became aware of the Board's decision on or about 5 February 1991. The Kujala Group consequently filed a letter outlining their concerns with the approved route on 26 February 1991.

Secondly, with respect to TransAlta's procedural objection that the Kujala Group should be considered the applicant at the hearing, the Board considers that a hearing granted pursuant to section 43 is a hearing in the first instance. In other words section 43 provides relief to persons affected by an order or direction of the Board by giving them the right to apply within 30 days for a hearing of the application. The application to be heard pursuant to section 43 is the application which was granted by the Board without a hearing. As a result, in this case the Board considers that TransAlta is the applicant.

4 CONSIDERATION OF THE APPLICATION

At the hearing TransAlta waived its procedural objections to the hearing and consented to an amended Order which would substitute the alternative route ADC, as suggested by the Kujala Group, for the previously approved 8-mile segment of line identified as ABC. TransAlta also indicated that the alternative route segment would cost approximately $27 000 less than the previously approved route, mainly because of less brushing and tree clearing. It further indicated that alignment ADC passes by approximately 10 fewer residences than route segment ABC. TransAlta added that the type of structures, average span length, and mid-span clearances would be similar to those applied for along the originally approved alignment. As in the case of approved route segment ABC, it stated that any existing distribution or rural circuits would be understrung on the structures along the new alignment. TransAlta concluded by stating that it is not aware of any constraints, environmental or otherwise, that would preclude it from routing a transmission line along segment ADC. TransAlta also stated that the occupants of the three residences on the alternative routing generally agreed with the proposal.

The Kujala Group indicated that it had no objection to the amended route, indicating that the new route had a number of advantages over the previously approved route. The Kujala Group also indicated that they were unaware of any objections to the alternative route.

The Board notes that TransAlta consented to a Board Order varying the original Order granted by agreeing to the alternative route ADC suggested by the Kujala Group. The remaining portion of line would be as originally applied for, as indicated on the attached figure.

With respect to the amended route segment, the Board notes that it would cost some $27 000 less, because of less brushing and tree clearing, and there would be 10 fewer residences in close proximity to the line, as compared to route ABC. As well, the Board notes that TransAlta indicated that pole structures, span length, and clearances would be similar to those for the originally approved alignment ABC. The Board is satisfied with TransAlta's stated committment regarding flexibility in determining final pole placement in consultation with affected landowners. The Board notes that no objections to the proposed line along segment ADC were received either prior to or during the hearing and that no environmental, technical, or routing constraints were identified along the amended route. The Board therefore finds the re-route of line 848L acceptable.

5 DECISION

For the reasons noted above, the Board has decided to grant TransAlta's Application 901415, as amended.

DATED at Calgary, Alberta, on 19 July 1991.

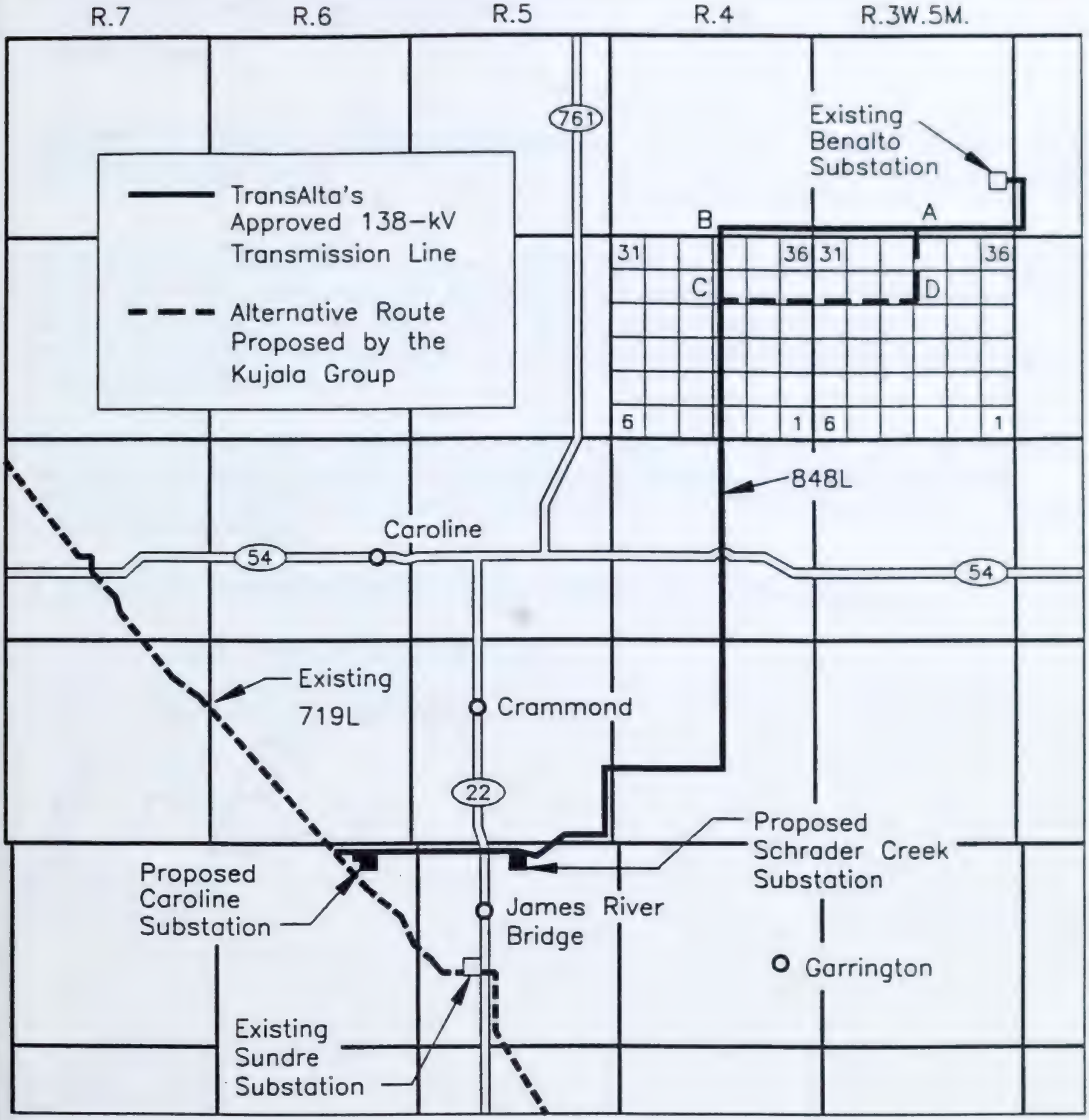
Dr. B. Bietz, P.Biol.
Board Member

Michael J Bruni

M. J. Bruni
Acting Board Member

Langlo.

C. A. Langlo, P.Geol.
Acting Board Member


R.7
R.6
R.5
R.4
R.3W.5M.
T.38
T.37
T.36
T.35
T.34
TransAlta's Approved 138-kV Transmission Line
Alternative Route Proposed by the Kujala Group
Existing Benalto Substation
A
B
C
D
31
36
31
36
6
1
6
1
761
848L
Caroline
54
54
Existing 719L
Crammond
22
Proposed Schrader Creek Substation
Proposed Caroline Substation
James River Bridge
Garrington
Existing Sundre Substation

BENALTO – CAROLINE AREA
Application No. 901415
TransAlta Utilities Corporation

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

THE CITY OF EDMONTON (EDMONTON POWER)
GENESEE POWER PLANT

Interim Decision D 91-12
Application 910336

The Board has considered Edmonton Power's application and the evidence presented at a hearing held on 15 August 1991. Having regard for its responsibilities under the Hydro and Electric Energy Act, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to issue an approval to Edmonton Power allowing the second unit at the Genesee Power Plant, Genesee 1, to be completed by October 1994.

The Board would not restrict Edmonton Power from completing the unit earlier to take advantage of the benefits described by Edmonton Power at the hearing. However, completion of the unit for service prior to the 1994/95 peak demand would be a decision for which Edmonton Power would have to accept full responsibility.

A further report providing detailed reasons for the decision will be forthcoming.

DATED at Calgary, Alberta, on 5 December 1991.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

F. J. Mink, P.Eng.
Vice Chairman

R G Evans

R. G. Evans, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION BY POLARIS PETROLEUMS LTD.
FOR RESCISSION OF BOARD APPROVAL NO. 2534
JOSEPH LAKE AREA – JOARCAM VIKING POOL

Decision D 91-13
Application 910665

1 INTRODUCTION

1.1 Application and Interventions

Polaris Petroleums Ltd. (Polaris), on behalf of itself and other major working-interest owners in the proposed Joarcam Viking Gas-Cap Unit, applied to the Energy Resources Conservation Board (ERCB) for immediate termination of Approval No. 2534 (the Approval). The application was made under section 4(d) of the Oil and Gas Conservation Act on the basis that continued production of gas under the Approval fails to afford the gas-cap owners the opportunity to obtain their share of the gas production from the Joarcam Viking Pool.

Total Petroleum Canada Ltd. (Total) submitted a letter in support of the application. Interventions opposing the application were submitted by Norcen Energy Resources Limited (Norcen) and BP Resources Canada Limited (BP). Petro-Canada Inc. submitted a letter opposing the application but did not submit evidence or cross-examine at the hearing. Bow Valley Industries Ltd. filed a submission but did not appear at the hearing. Gulf Canada Ltd. did not file a submission but stated at the hearing that Polaris speaks on its behalf.

1.2 Hearing

A public hearing of the application was held in Calgary, Alberta, on 13 and 14 August 1991, before Board Members R. G. Evans, P.Eng., and N. G. Berndtsson, P.Eng., and Acting Board Member K. G. Sharp, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Polaris Petroleums Ltd. (Polaris) B. O'Ferrall	R. K. Craig, P.Eng. B. J. Howse, P.Eng.
Norcen Energy Resources Limited (Norcen) J. P. Peacock, Q.C.	D. R. Barber, P.Eng. B. W. Jensen, P.Eng.
BP Resources Canada Limited (BP) D. A. Holgate	P. Chan, P.Eng. B. Lee, P.Eng.
Total Petroleum Canada Ltd. (Total) D. R. Shantz, P.Eng.	

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Gulf Canada Resources Ltd. (Gulf) D. Phillips	
Petro-Canada Inc. S. R. Miller	
Energy Resources Conservation Board staff R. D. Heggie A. Warren, P.Eng. A. R. Olive	

2 BACKGROUND

The Joarcam Viking Pool was discovered in 1949 and extensively developed in the 1950s. This lenticular offshore sand bar is delineated by over 500 oil wells drilled on 16-hectare spacing, and 18 gas wells. The Viking Sand in this pool is the main sand of three found within the Lower Cretaceous Viking Formation and extends over four townships in length, as shown on the attached figure. It is relatively thin. The oil accumulation is partially overlain by an updip associated gas cap. An aquifer present along the downdip edge of the pool provides some energy influx, especially in the Joseph Lake area of Township 50, Range 22, West of the 4th Meridian.

Up to 1963, all of the pool's oil production was obtained under primary depletion. In 1963, a waterflood scheme was instituted in Joarcam Viking Unit No. 1. Produced gas reinjection commenced in Joarcam Viking Units 2 and 3 in 1967 as a means of pressure maintenance. In 1981, the gas-reinjection scheme in Unit No. 2 was converted to a waterflood scheme but produced gas continued to be reinjected. In 1985, a waterflood scheme was initiated in the northern part of Unit No. 3, replacing part of the gas-reinjection scheme. Finally, in 1988, the remaining portion of Unit No. 3 was converted to pressure maintenance by water injection, although gas injection continues.

The south end of the pool is essentially depleted and most of the wells are abandoned. This area represents approximately 11 per cent of the pool's original oil in place. The Joseph Lake area in the north end of the pool is the main active primary oil-producing portion of the pool and represents approximately 22 per cent of the total pool original oil in place.

In 1973, the Joarcam Viking Pool was placed on good production practice (GPP) for administrative simplicity but that status was rescinded for equity and conservation reasons on 1 December 1975. Although drilling was delineating a gas cap, it could not be produced until a scheme (or schemes) for concurrently producing oil and its associated gas was approved in accordance with sections 26 and 29 of the Oil and Gas Conservation Act. With a commitment to conserve the produced gas in the Joseph Lake oil-producing area, which at the time was being flared, the Board advertised an application by Norcen for GPP (Application No. 770108). The notice indicated that, if the application were granted, the approval of GPP would be subject to a number of conditions. Several objections were received and the application was subsequently considered at an examiners' hearing held on 5 July 1977. Upon recommendation of the examiners, the Board approved concurrent production for a specified area (the

Approval area*), and the examiners' report of Application No. 770108 (the Examiners' Report), and Approval No. 2534 containing the following provisions, were issued:

- all gas must be conserved by an approved gas conservation scheme,
- gas-cap production (within the Approval area) shall be permitted from oil wells only, and
- each well within the Approval area shall be subject to an MRL of 636 m^3 of oil per month and this MRL shall be subject to a gas-oil ratio penalty calculated by applying the producing gas-oil ratio to Schedule 6, Part A, Table 70 of the Oil and Gas Conservation Regulations, and such calculations shall be based on the gross gas production from each well.

On 31 January 1991, Polaris, on behalf of itself and other working-interest owners in the proposed Joarcam-Viking Gas Cap Unit, filed an application with the ERCB (Application No. 910193) for

- approval of concurrent gas-cap production from the Joarcam Viking Gas Cap, and
- review and amendment of Approval No. 2534.

As a result of objections to certain aspects of the application and because of what it believed was continued inequitable drainage under the Approval, Polaris filed the current application for immediate termination of the existing Approval No. 2534 and suspension of Application No. 910193.

3 PRELIMINARY MATTERS

At the outset of the hearing Polaris amended its application by seeking a rescission of the Approval pursuant to section 42 of the Energy Resources Conservation Act. Section 42 provides that the Board may review, rescind, change, alter or vary an order or direction made by it, or may rehear an application before deciding it.

Polaris requested immediate termination of the Approval. It claimed that the Approval fails to protect the interests of the gas-cap owners outside of the Approval area, as anticipated in the Examiners' Report. Polaris submitted that attempts to unitize the gas cap have not been successful and therefore, until such time as the Approval is terminated, meaningful negotiations towards achieving an equitable formula and plan to unitize and produce the gas cap are stalled.

Norcen requested that the Board deny the application so that efforts towards a negotiated settlement of this matter can proceed. Norcen argued that no breach of the Approval had been alleged and that Norcen had not taken any steps to preclude the gas owners from producing their gas. Norcen stated that it had participated in the unitization process in good faith and remains committed to that process.

BP submitted that it would be directly and adversely affected by termination of the Approval. BP contended that in determining whether or not to rescind an existing approval, the Board should examine if the operations authorized under that approval remain consistent with the public interest.

---

* The "Approval area" used throughout this report is that area referred to in Approval No. 2534. The "Joseph Lake area" and "Approval area" are used interchangeably in the report, as is the case for most of the records of the hearing; however, in some cases the "Joseph Lake area" may not always be as specific as the "Approval area".

BP claimed that the provisions of the Approval have afforded, and continue to afford, recognition of the interests of gas-cap owners. BP stated that it is prepared to enter into and conclude meaningful negotiations towards an equitable formula and plan to unitize and produce the gas cap without rescission of the Approval.

The Board, having heard the arguments of all parties, concludes that a review of the Approval is appropriate. Since the Approval was issued approximately 14 years ago, new wells have delineated the gas cap and the producing characteristics of the Approval area have become well established. Also, the cumulative volumes of oil production from the pool and from the Approval area are indicative of pool maturity.

Notwithstanding the need to review, alter, or rescind the Approval, the Board perceives that there is general agreement among the hearing participants concerning the need for continued unit negotiations to resolve the current impasse. The Board understands that several areas of disagreement have prevented formation of the proposed unit and have led to this hearing. These issues appear to be centred on the ownership of the remaining gas in place and the sharing of revenues from sale of this gas.

The interveners proposed that revenues from the sale of produced gas above an agreed-to gas-oil ratio (GOR) cut-off, net of operating costs and royalties, be placed in a trust account pending formation of the gas-cap unit and Board approval of Application No. 910193.

The Board notes that the parties did not request the Board to consider the question of allocating funds or production "in kind" to trust accounts or to be held in escrow; therefore, it will not consider or rule on this proposal. The Board encourages operators to pursue all avenues of co-operation which would lead to a negotiated settlement for continued maximization of hydrocarbon recovery from the Joarcam Viking Pool, including the concept of a trust account if the parties deem it appropriate.

4 ISSUES

Having concluded that a review of the Approval is appropriate, the Board considers the main issue to be the need to rescind the Approval. In considering this issue, the following sub-issues are apparent:

- gas-cap gas drainage
- hydrocarbon recovery
- feasibility of reinjecting non-solution gas production

5 GAS-CAP GAS DRAINAGE

5.1 Views of the Applicant

Polaris submitted that essentially all current gas production from the Approval area is associated gas. In its opinion, the aggregate gas production has substantially exceeded the original recoverable gas in that area. The applicant contended that GPP with a maximum rate limitation (MRL), resulting from the decision on Norcen's application 14 years ago, was deficient over time because it did not have a specific volume constraint, but simply a rate constraint. Polaris claimed that the MRL, as approved, is in fact an open-ended opportunity to continue to produce gas. Polaris emphasized that during the examiners' hearing of 1977 that resulted in issuance of the Approval, it was generally accepted that the proposed scheme would cause increased gas-cap drainage into the oil zone and any gas that might migrate from outside of the Approval area would be available for production. Polaris estimated that 353 x 10^6 m^3 of solution and gas-cap gas were initially recoverable in the Joseph Lake area. Polaris observed that 465 x 10^6 m^3 has been produced, indicating that there has been drainage into the area and that this drainage is from lands outside of the Approval area. This drainage is supported by its material-balance calculations which show influx of gas into the Joseph Lake area and gas efflux from the gas-cap area.

When questioned about the accuracy of its reserve estimates, Polaris made reference to a map that Esso Resources Canada Limited submitted to the Technical Committee in 1988. It stated that the map supports a gas-cap volume for the Joarcam Viking Pool of 1844 x 10^6 m^3, which is close to the 1850 x 10^6 m^3 calculated using the material balance. Polaris acknowledged that the accuracy of the material balance could be plus or minus 20 to 25 per cent. The greatest potential source of error in the calculation is reservoir pressure data, which are sparse, particularly in the Joseph Lake area.

When asked to comment on the range of gas-in-place estimates presented in Norcen's intervention, Polaris disputed the accuracy of these estimates. The applicant defended its estimate as being the most probable.

5.2 Views of Norcen

Norcen submitted a table of four gas-cap gas-in-place estimates for the Joseph Lake area ranging from 195 x 10^6 m^3 (Polaris) to 480 x 10^6 m^3 (Norcen 1984 Waterflood Study). The intervener stated that the complexity of the pool production mechanisms makes calculations of the initial gas in place difficult. Because of the variations in the gas-in-place estimates, uncertainty exists with respect to the amount of drainage that may have occurred. Norcen acknowledged that gas-cap drainage has been significant enough that Norcen has devoted much time and effort to try to come to a solution with the gas-cap owners that would allow the drainage to stop, or to reach an agreement on the sharing of the revenue from sale of the gas.

Under cross-examination Norcen acknowledged that the main issue to be resolved through unit negotiation is that of compensation for past drainage, but it believed that the ongoing drainage issue can be taken care of through agreement to an allocation formula.

5.3 Views of BP

BP did not submit evidence relating to the issue of gas-cap drainage. However, under cross-examination it contended that there has not been any serious drainage. BP acknowledged that gas-cap migration has taken place but was unable to conclude in which direction the gas was migrating. The intervener estimated that some gas migration from the gas cap is either just beginning or will take place soon. The intervener did not quantify how much migration has taken place. BP expressed concern that shutting in the Joseph Lake wells would result in migration of Joseph Lake oil into Unit No. 3 to the south and perhaps into the gas cap.

5.4 Views of the Board

As demonstrated by the range of gas-in-place estimates summarized in Norcen's intervention, which includes the Polaris estimates, the question of drainage is very complex. However, the evidence presented leads the Board to conclude that volumes of gas-cap gas from outside the Approval area have moved and are moving into the area and therefore drainage is a legitimate concern. The limited pressure information further suggests that gas is moving into the Approval area from outside. Although not a unique answer, the Polaris material-balance calculations, using those pressure data, provide results that indicate significant movement of gas-cap gas volumes.

In general, pressure information provided at the hearing and the existence of water injection wells along the north boundary of Unit No. 3 suggest that in the short term, the movement of oil from the Approval area to Unit No. 3 would be unlikely.

The Board concludes that production operations under the existing Approval are causing drainage from the gas-cap area outside the Approval area, hence an impact on the gas owners outside the Approval area. This impact must be weighed against the conservation benefit or overall hydrocarbon recovery to be achieved under the Approval.

6 HYDROCARBON RECOVERY

6.1 Views of the Applicant

Polaris submitted, as part of its argument for termination of the Approval, a summary comparing oil and gas production of various oil-interest owners and the percentage of gas revenue compared to total hydrocarbon revenue for each of the owners. The summary showed that, on average, the various parties were obtaining at least 10 per cent of their revenue from gas production. In the case of the higher-GOR wells, 36 to 52 per cent of the revenue was from gas production.

The applicant argued that an MRL of 20.9 m^3/d per well was authorized in the Approval to provide a gas rate of approximately 42.3 x 10^3 m^3/d, which was seen as sufficient to justify its gathering and processing. Although the per-well oil withdrawal rate is of limited concern to those gas-cap owners outside of the Approval area, so long as the gas produced with the oil is reinjected, the justification for this anomalously high oil rate no longer exists. That being the case, Polaris suggested that the Board may wish to re-examine its continued justification from an oil-conservation perspective. When asked what would be an appropriate MRL if the Approval were rescinded, Polaris stated that there is no particular oil rate, the main concern being the gas-cap production.

Polaris contended that rescinding the Approval would not have an effect on hydrocarbon conservation. The applicant admitted that continuation of the Approval may have some effect, to the extent that oil operations are partially subsidized by gas revenue which does not belong to the oil owners. Consequently those oil owners have a lower economic limit than oil production alone would afford them. The applicant claimed that with the termination of the Approval, there would be little or no oil production because of the imposition of the GOR penalty. Polaris further submitted that because the shutting-in of oil wells would be temporary, conservation would not be an issue.

6.2 Views of Norcen

Norcen contended that rescission of the Approval would lead to the shut-in of all or most of the oil wells in the Approval area. Norcen submitted that for the month of June 1991, the Approval-area oil wells produced 140 m^3/d. This compares to their capability of 180 to 200 m^3/d. The intervener argued that gas production below the turndown rate of the compressor (24 x 10^3 m^3/d) would lead to only three options: shutting in the oil wells, downsizing the compressor, or flaring gas. When questioned as to what would be an appropriate MRL to maintain production (subject to Base GOR of 70 m^3/m^3) and the operation of the compressor facilities, Norcen stated that rates of 9 or 10 m^3/d per well would permit continued production. An MRL below this rate would cause operational problems with its facilities and therefore would be unsatisfactory.

6.3 Views of BP

BP did not specifically provide its views on hydrocarbon recovery but submitted that rescinding the Approval would lead to production and economic losses, noting that its wells are capable of producing 35 m^3/d of oil and 11 x 10^3 m^3/d of gas. BP argued that its wells cannot be produced without some associated gas and hence, rescission of the Approval could force these wells to be shut in.

6.4 Views of the Board

The Approval was issued to maximize hydrocarbon recovery by providing an economic rate of oil and gas production to ensure the feasibility of gas conservation. The conditions imposed by the Approval were intended to control excess gas-cap production and to adequately protect the rights of the gas-cap owners. The Board believes that the Approval has provided for efficient total hydrocarbon recovery and could continue to do so. However, concurrent-production considerations must have regard for the total hydrocarbon recovery and an equitable sharing of that recovery by the respective owners of the oil and the gas-cap gas. The Board recognizes that gas-cap drainage is taking place and will continue under the Approval. It therefore concludes that the owners of the Joarcam Viking Pool gas cap are not being adequately protected by the Approval.

Considering whether a rescission, or alteration, of the existing Approval would affect hydrocarbon recovery, the Board believes that oil recovery may be affected to a small degree. This effect could be very small, if a concurrent-production scheme acceptable to all parties is devised and approved by the Board within the next few months. The Board concludes that concern for overall hydrocarbon recovery by rescinding or altering the Approval is minimal compared to the inadequate gas-cap owner protection that the conditions in the present Approval provide.

7 FEASIBILITY OF REINJECTING NON-SOLUTION GAS PRODUCTION

7.1 Views of the Applicant

Polaris submitted that its material-balance studies have demonstrated that drainage has occurred and producers in the Approval area should not be entitled to keep gas-cap gas. Hence Polaris requested immediate reinjection of all gas-cap gas back to the Viking zone as an alternative condition of continued oil production. Polaris did not submit evidence as to the cost of reinjecting the gas nor has it undertaken any studies to determine whether or not reinjection would have an impact on ultimate oil recovery from the pool. Further, Polaris acknowledged that the reinjected gas would not all be recovered in the future. However, the applicant believed that it was neither unfair nor untimely to suggest that the cost of continued oil production should properly be at the expense of the oil producers reinjecting produced gas-cap gas.

7.2 Views of Norcen

Norcen submitted that reinjection of gas-cap gas produced from the Joseph Lake area is both uneconomic to implement and unnecessary to mitigate equity concerns. The intervener stated that reinjection would require modifications and additions to existing facilities as well as the conversion or drilling of a new well for gas injection. Norcen had reviewed the effects of reinjection on incremental recovery and found that there was no recovery enhancement under such a scheme. Norcen estimated that 5 per cent of the gas reinjected would be unrecoverable.

7.3 Views of BP

BP opposed the reinjection of gas-cap gas production into the Viking Formation as it seems inconsistent with the applicant's request for termination of the Approval. The intervener argued that, as well as being a substantial investment, the amount of gas eventually to be recovered is speculative. Further, reinjection could have an adverse conservation effect resulting from potential trapped-gas saturation losses. Finally, BP submitted that reinjection is not an option, as it does not make sense to produce and then reinject and produce the gas again.

7.4 Views of the Board

Notwithstanding the absence of definitive economics on gas reinjection, at this late stage of the pool's life and with gas-cap production pending, the Board believes that the investment in injection facilities should be considered as a last option only. The volumes of gas that would be required to operate injection facilities and the reinjected volumes of gas that would be unrecovered under a concurrent-production scheme, do not represent economic and orderly development when compared with a potential agreement between the gas-cap owners and the oil owners for a concurrent-production scheme for the pool.

The Board believes that a scheme of joint management of the hydrocarbon recovery would better represent economic and orderly development.

8 FINDINGS

The Board finds that the basis on which the Approval of concurrent production in the Joseph Lake area was granted in 1977 is no longer fully valid. The Approval identifies the major primary producing area of the pool, provides for hydrocarbon recovery and conservation, and permits concurrent production of the oil zone and the gas cap in a specific area under certain controls. While the Approval in its present form provides for good oil recovery, it permits more drainage than is acceptable from the gas-cap area into the Approval area. The Board believes, however, that given the present circumstances, it would be better to retain the Approval in some altered form than to rescind or suspend it. Rescinding the Approval could result in complete shut-in of production from the Approval area of any well that has a producing GOR significantly exceeding the solution GOR. The Board believes that this would effectively shut in the oil production and gas conservation facilities in the Approval area.

Altering the Approval by imposing an MRL of 10 m^3 of oil per day per well subject to a GOR penalty base of 70 m^3/m^3, for an interim period, would reduce the gas-cap production and still permit oil recovery from the Approval area. The Board believes that the produced gas volumes under these MRL and penalty restrictions would also permit continued operation of the gas conservation facilities.

The resulting balance between continued production of oil and gas and reduced gas-cap production is expected to provide a more equalized opportunity and incentive for unitization negotiations between the parties. The Board believes that it would be desirable for the parties to complete the unitization agreements and proceed with an application for a concurrent-production scheme that encompasses the full oil-zone and gas-cap areas of the pool. If the parties continue to be unable to resolve the gas-cap gas production-sharing problem, a further review of the altered Approval on the basis of the observed performance should occur. To accomplish this, the Board would expect reports from the interested parties and these, together with its own assessment, would be the basis upon which the Board would review the appropriateness of the Approval and its conditions.

9 DECISION

The Board denies Application No. 910665 to rescind Approval No. 2534 but, as discussed in the findings, the Board will alter the Approval to reflect the following conditions:

- all gas must be conserved by an approved gas conservation scheme,
- gas-cap production (in the Approval area) shall be permitted from oil wells only, and
- each well within the Approval area shall be subject to an MRL of 10 m^3 of oil per day and this MRL shall be subject to a gas-oil ratio penalty calculated by applying the producing gas-oil ratio to a Base GOR of 70 m^3/m^3.

The Board will issue an amendment to Approval No. 2534 to make these conditions effective 1 November 1991.

In the event that a resolution of the gas-cap production-sharing matter is not achieved, the interested parties shall jointly or separately review the production performance of the area and provide the Board's Oil Department with a report on or before 28 February 1992 discussing the effects of this decision on gas-cap drainage and the operation of the gas conservation facilities. Based on those reports and its own assessment, the Board will review the continuance of the altered approval and determine whether or not further alterations are appropriate.

DATED at Calgary, Alberta, on 7 October 1991

ENERGY RESOURCES CONSERVATION BOARD

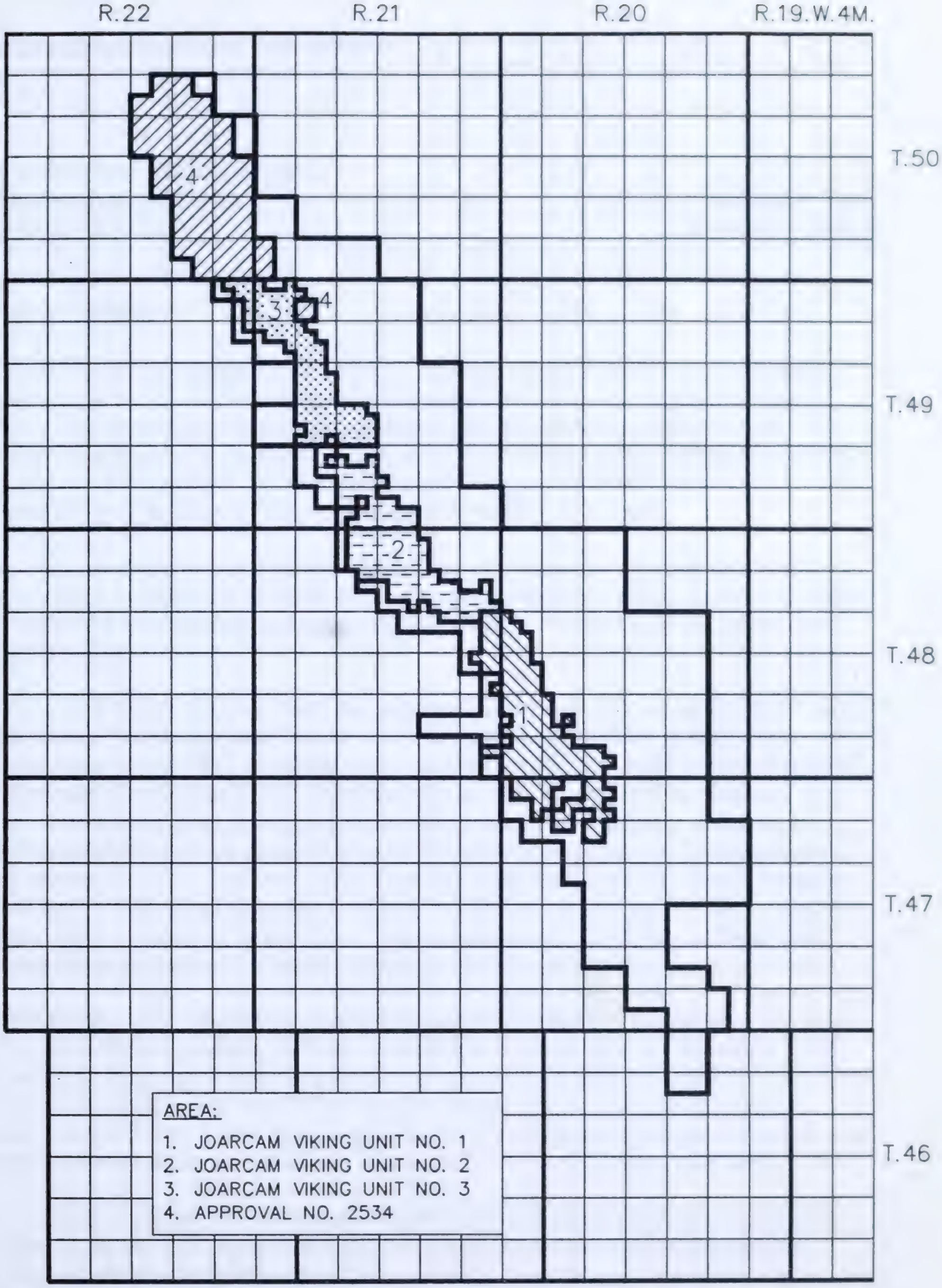
R G Evans

R. G. Evans, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Board Member

K G Sharp

K. G. Sharp, P.Eng.
Acting Board Member


R.22
R.21
R.20
R.19.W.4M.
T.50
T.49
T.48
T.47
T.46
4
3
4
2
1
AREA:
1. JOARCAM VIKING UNIT NO. 1
2. JOARCAM VIKING UNIT NO. 2
3. JOARCAM VIKING UNIT NO. 3
4. APPROVAL NO. 2534

JOARCAM VIKING POOL
Application No. 910665

D 91-13

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

TRANSALTA UTILITIES CORPORATION
138-kV TRANSMISSION LINE 848L
BENALTO-CAROLINE AREA

Decision D 91-14
Application 901415

1 INTRODUCTION

On 2 October 1990, TransAlta Utilities Corporation (TransAlta) applied to the Energy Resources Conservation Board (the Board), pursuant to sections 12 and 14 of the Hydro and Electric Energy Act, for approval to construct approximately 65 kilometres (km) of 138-kV transmission line designated as 848L from Benalto to the Caroline area and the related substation facilities required to connect and operate it. The proposed facilities would serve the approved Shell Caroline gas development project as well as other electric loads that are developing in the area.

The application was considered in late 1990 with notice issued to potentially affected parties on 29 October 1990. The two objections received were successfully resolved by the applicant, the Board completed its review of the application, and the necessary permits and licences for the project were issued on 22 January 1991.

Subsequent to approving the project, the Board was contacted by a group of local landowners referred to as the "Kujala Group" which expressed several concerns regarding a 12.8-km (8-mile) section of the approved route identified as ABC, as shown on the attached figure. The Kujala Group suggested an alternative alignment identified as ADC. TransAlta subsequently investigated the proposed alternative route, considered it to be viable, and indicated that it would be prepared to amend its application provided consent could be obtained from all the newly affected parties. After contacting all parties along alternative ADC, TransAlta advised the Board and the Kujala Group that agreement could not be obtained from all affected parties and that it would proceed to construct the transmission line on its original route as approved by the Board. As a result, the Kujala Group, by letter dated 8 May 1991, requested that a hearing be held to determine which route would be the most suitable.

In response to the Kujala Group request, the Board, pursuant to section 43 of the Energy Resources Conservation Act, directed that a hearing be held in Innisfail to consider the route alternative ADC along with the entire originally applied-for route. The hearing took place on 26 June 1991 in Innisfail and the Board found the route alternative ADC acceptable for the reasons contained in Decision D 91-11 issued on 19 July 1991. Permit and Licence No. CP 91-43 approving transmission line 848L including the amended route alternative ADC was issued from the Board's offices on 8 August 1991.

In August 1991, Mrs. M. McKay, who owns land on both sides of the road allowance (also shown on the attached figure) along the ADC route, contacted the Board's Hydro and Electric Department indicating that she had not received notice of the hearing held in June 1991 and objected to the newly approved route segment ADC.

2 NOTICE AND HEARING

In response to Mrs. McKay's request, the Board, pursuant to section 42 of the Energy Resources Conservation Act, directed that the matter be reviewed in order to give Mrs. McKay an opportunity to present her views and make her position known.

The application was further considered at a hearing in Innisfail on 19 November 1991 by the original panel of 26 June 1991, Dr. B. F. Bietz, P.Biol. (Chairman), M. J. Bruni, and C. A. Langlo, P.Geol., sitting. Those who attended the hearing are listed below.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
TransAlta Utilities Corporation (TransAlta) J. G. Friesen	R. J. Wilkie, P.Eng. A. S. Rutkunas, P.Eng. J. C. Chalmers, C.E.T.
Kujala Group G. Kujala	G. Kujala
M. McKay P. R. Mack	M. McKay
V. Ceccato	V. Ceccato
R. Haslam	R. Haslam
Alberta Environment R. Grover	
Energy Resources Conservation Board staff M. L. Asgar-Deen, P.Eng. T. Chan, P.Eng. B. E. Olliver	

3 PRELIMINARY MATTERS

At the outset of the hearing TransAlta raised several procedural objections. TransAlta contended that the Board did not have jurisdiction pursuant to section 29(2) of the Energy Resources Conservation Act to re-open a hearing to consider Mrs. McKay's concerns. It also claimed that, since Mrs. McKay was provided notice at the address shown on the Certificate of Title, compliance with the requirements of section 29(2) had been achieved. Finally, TransAlta argued that it should not be considered the applicant in this case as it was not seeking an amended route for the transmission line. It contended that, since Mrs. McKay was challenging a decision and permit issued by the Board, she should be considered the applicant. TransAlta requested a ruling from the Board on these matters prior to any evidence being given.

Mrs. McKay submitted that TransAlta was aware that she objected to the proposed ADC route and that she did not reside at the address shown on the Certificate of Title. She concluded by stating that, because she had not received notice of the June 1991 hearing and had not had an opportunity to be heard, she should be given the same intervener status accorded the Kujala Group.

The Board concluded by stating that under section 42 of the Energy Resources Conservation Act it has the authority to review an order or direction made by it. In this case it had come to the Board's attention that there were changed circumstances. A directly affected party, who did not receive notice of the previous hearing, had filed an objection. The Board stated that it was satisfied that Mrs. McKay had not been given proper notice and, because it is bound by procedural rules of fairness set out in section 29(2) of the Energy Resources Conservation Act, the Board decided to re-open the hearing to provide Mrs. McKay the opportunity to have her views considered.

With respect to TransAlta's contention that it should not be considered the applicant, the Board stated that this hearing was originally convened to consider Application 901415 submitted to the Board by TransAlta. The Board re-stated its view that the original application was still under review, pursuant to section 42, and that TransAlta was therefore the applicant. TransAlta accepted this ruling without prejudice to appeal at some future date and the hearing resumed.

4 ISSUES

The Board notes that at the hearing, TransAlta reconfirmed the need for and timing of the transmission line by indicating that the line should be commissioned by 1 April 1992 in order to provide a reliable power supply to the Shell Caroline gas development project. The Board accepts this latest information and notes that no one questioned the need for the transmission line.

The Board considers the issues with respect to this hearing to be

- adequacy of the applicant's route selection process, and
- impacts associated with the original and amended routes.

5 ADEQUACY OF THE APPLICANT'S ROUTE SELECTION PROCESS

5.1 Views of the Applicant

In examining potential routes to accommodate this transmission line project, TransAlta investigated numerous route alternatives within a study area encompassing some 400 square miles.

TransAlta submitted that it selected its originally applied-for route based on its standard route selection criteria which include electrical, regulatory, social, environmental, engineering, and cost considerations. It went on to state that seldom will all criteria favour the same route, so the final route selected in this instance was a compromise between these criteria. The applicant concluded by stating that the applied-for route takes advantage of significant lengths of straight line and open road allowance alignment, minimizing the number of angles and reducing the overall cost.

In response to questioning from the interveners, TransAlta explained that it had rejected a possible route adjacent to the existing 240-kV steel tower transmission lines located across private property on an alignment extending south from Benalto substation. It indicated that if the proposed wood-pole 138-kV line, with a much shorter span length, were placed along the same right of way with the existing 240-kV lines, there would be additional obstructions between the 240-kV structures, and this would result in an unacceptable level of impact on farming operations. As well, placing the line either along the north-south road allowance directly south of Benalto or along the Secondary Highway No. 766 alignment was not considered desirable as the line would have conflicted with major Alberta Government Telephone facilities located along these alignments that would have required very expensive mitigation.

Other routing options investigated farther to the west of Benalto were found to be unsatisfactory, as the area is very wet and few lengthy sections of open road allowance exist.

In investigating the Kujala Group's alternative ADC, TransAlta found this 12.8-km (8-mile) segment to be a viable alternative for the reasons discussed in Section 6 of this report.

TransAlta, in looking at the alternative route suggested by Mrs. McKay, found it to be unacceptable for reasons discussed in Section 6 of this report.

5.2 Views of the Interveners

Mrs. McKay submitted that the materials filed by TransAlta do not adequately explain the route selection process and, accordingly, do not demonstrate why the Board should not direct a review of alternative routes by the applicant. She questioned why a possible route adjacent to the existing 240-kV steel tower transmission lines south of Benalto or a route along Secondary Highway No. 766 was not selected.

The Kujala Group did not question TransAlta's route selection process but simply stated that it believed it had identified a more acceptable route along the ADC alignment 2 miles south of the applied-for ABC route. Its reasons are discussed in Section 6 of this report.

5.3 Views of the Board

The Board is satisfied that the standard route selection process developed and in current use by the applicant would allow it to adequately identify and address the broad range of concerns and considerations necessary in determining appropriate transmission line routes. The Board also recognizes that in any area with multiple land uses, all possible route options will likely require some compromise between a number of factors. In this instance, the Board is satisfied that TransAlta investigated a number of possible alignments within a sufficiently large study area prior to selecting a route. The Board therefore will not require the applicant to investigate any other route alignments.

6 IMPACTS ASSOCIATED WITH THE ORIGINAL AND AMENDED TRANSMISSION LINE ROUTES

6.1 Views of the Applicant

TransAlta stated that its route selection process includes a review of the compatibility of the project with people and their activities. In this case, following road allowances would have the least impact on agricultural operations and would avoid encumbrances on private land.

In looking at its original ABC alignment as compared to the amended ADC alignment, TransAlta noted that there are ten residences within 500 feet of the line on the original ABC alignment while only three residences exist within 500 feet on the amended ADC alignment.

Additionally, TransAlta identified six locations on the original ABC alignment that would require tree clearing and brushing as compared to only one location requiring this on the amended ADC alignment. Because of reduced tree clearing and brushing on the amended ADC alignment, TransAlta indicated it would realize a net saving of some $27 000 even though two more corner structures would be required for this route.

With respect to Mrs. McKay's proposed alternative route, TransAlta indicated it would require four additional angle structures and associated guy wires. As well, it would cost an additional $72 000 for this alignment which would in part be located diagonally across private property. For these reasons TransAlta found this route unacceptable.

With respect to electric and magnetic fields (EMFs), TransAlta stated that it had kept abreast of developments in the research related to this area. It expressed the opinion that, although research was continuing, there had been no substantive change in the scientific knowledge related to this issue. TransAlta noted that Mrs. McKay indicated that her proposed residence would be located some 200 feet away from the road allowance. At the hearing TransAlta submitted evidence which depicted how magnetic field strengths would vary with distance from the centre of the transmission structure located on the road allowance. Using this information, TransAlta stated that at this distance, the magnetic field strength would be in the range that would be experienced within a typical residence.

6.2 Views of the Interveners

Mrs. McKay stated that her main concern with the proposed ADC route was that EMFs associated with the proposed transmission line would present a health hazard to present and future occupants of her properties. She noted that all EMF studies, although inconclusive as to whether or not high-voltage transmission lines cause adverse health effects, recommend prudent avoidance.

Mrs. McKay proposed an alternative route around the perimeter of her 5-acre parcel north of the road allowance. She stated that her fears of health effects from EMFs would be resolved if the line were built along her suggested alternative.

She concluded by stating that the presence of the transmission line would impede her ability to rent her property and indicated that a prospective tenant, Mr. Haslam, has advised that if the transmission line is constructed on the road allowance, he would not rent her property. Mr. Haslam confirmed he would not rent if the transmission line were approved on the ADC route.

Mrs. Ceccato, who owns property immediately west of Mrs. McKay's 5-acre parcel, was opposed to Mrs. McKay's suggested alternative as it would diagonally cross her property. She was in favour of the line remaining on the east-west road allowance ADC alignment 1 metre off her property.

The Kujala Group's concerns with the original ABC alignment focused primarily on land use with respect to inconvenience, nuisance, quiet enjoyment of property, the unsightliness of a large power line, and safety.

It cited the large number of residences (ten) that would be affected on the ABC route as compared to only three on the alternative ADC route and noted that considerably more tree clearing and brushing would be required along the ABC route compared to the ADC route. In its intervention it indicated that there are many more active farms along the ABC route as compared to the ADC route and that the danger of farm machinery coming in contact with the transmission line would be much greater along the ABC route.

6.3 Views of the Board

Notwithstanding the concerns expressed by Mrs. McKay, the Board is not satisfied that there are harmful health effects associated with EMFs from electric transmission lines. Therefore, it is of the opinion that the question of EMF-related health effects should not influence its decision on the appropriate location of the proposed transmission line.

The Board recognizes, as previously noted, that in multiple land-use areas, possible route options will require some compromise between a number of factors. In this instance, maximizing compatibility with existing land uses, including agricultural operations and distances from existing residences, were identified as the main differentiating factors between routes ABC and ADC. The Board noted in its previous decision that there are seven fewer residences along the ADC route and that cost of route construction would be less than on the ABC route. The Board also noted that the distances to residences from a line constructed along the ABC route would be closer than from one constructed along the ADC route and concluded that the ADC route results in less overall impact than the originally applied-for ABC route.

The Board believes that the alternative proposed by Mrs. McKay is not satisfactory owing to the additional cost that would be incurred and the impact on the Ceccato property. The Board is of the opinion that this type of wood-pole transmission line should be located on road allowance alignments off private property wherever practical.

In summary, the Board finds amended route alternative ADC acceptable.

7 DECISION

After careful consideration the Energy Resources Conservation Board has decided to grant TransAlta Utilities Corporation's Application 901415, as amended, and pursuant to Permit and Licence No. CP 91-43 TransAlta may proceed to construct 138-kV transmission line 848L from the Benalto substation to the Caroline substation.

DATED at Calgary, Alberta, on 19 December 1991.

ENERGY RESOURCES CONSERVATION BOARD

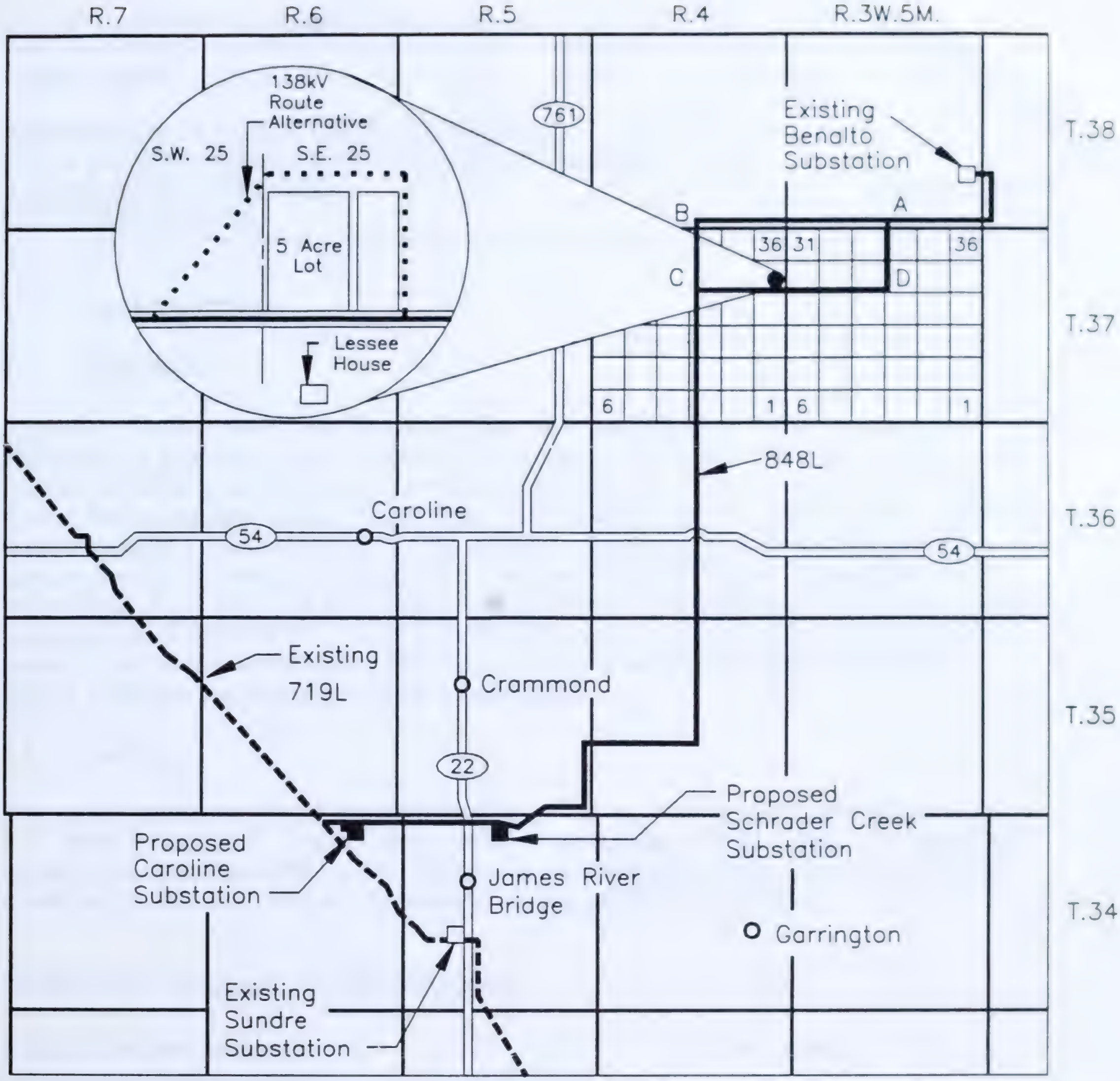
Dr. B. F. Bietz, P.Biol.
Board Member

Michael

M. J. Bruni
Acting Board Member

Langlo

C. A. Langlo, P.Geol.
Acting Board Member



━━ Proposed Route Alignments For 138-kV Transmission Line 848L

▪▪▪▪ Alternative Route Suggested By Mrs. M. McKay

BENALTO – CAROLINE AREA
Application No. 901415
TransAlta Utilities Corporation

D 91-14
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION BY BOW RIVER PIPE LINES LTD.
FOR A PERMIT TO CONSTRUCT A CRUDE OIL PIPELINE
AND PUMPING FACILITIES
SOUTHERN ALBERTA

Decision D 91-15
Application 911262

1 INTRODUCTION

1.1 Application

Pursuant to Part 4 of the Pipeline Act, Bow River Pipe Lines Ltd. (Bow River) submitted an application for approval to reverse the flow of a segment of its existing pipeline to transport crude oil from the Hays Pump Station located in legal subdivision (Lsd) 9, section 24, township 13, range 15, west of the 4th meridian, to the Fincastle Pump Station located in Lsd 11-8-10-15 W4M, to construct approximately 89.9 kilometres (km) of 273.1-millimetre (mm) outside diameter (OD) crude oil pipeline from the Fincastle Pump Station to the proposed Northern Pipeline Company (Northern) meter station at Lsd 16-7-1-16 W4M near Coutts, to upgrade its existing Chin Coulee Booster Station located at Lsd 12-6-8-15 W4M to 1270 kilowatts (kW), and to construct a new 1270-kW booster station at Lsd 16-18-2-16 W4M near Milk River. The proposed pipeline route (amended as per Section 1.3 of this report) is shown in the attached figure.

1.2 Hearing

The application was considered at a public hearing in Calgary, Alberta, with Board Members F. J. Mink, P.Eng., R. G. Evans, P.Eng., and N. G. Berndtsson, P.Eng., sitting. The hearing was opened on 12 November 1991 but was adjourned at the interveners' request. The hearing was re-opened on 15 November 1991 and continued on 18, 19, and 20 November 1991.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Bow River Pipe Lines Ltd. (Bow River)	Frank Janzen, P.Eng.
B. K. O'Ferrall	Randolph C. Aldridge
J.E.E. Lowe	Donald R. Fedoration, P.Eng.
Murphy Oil Company Ltd. (Murphy)	
F. M. Saville, Q.C.	
D. A. Holgate	
Home Oil Company Ltd. (Home)	Don Jones, P.Eng.
D. G. Hart, Q.C.	Michael J. Massecar, P.Eng.
C. I. Maclean	

THOSE WHO APPEARED AT THE HEARING (cont)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Anderson Exploration Ltd. (Anderson) Mike Keohane, P.Eng.	Mike Keohane, P.Eng. Ken McCagherty, P.Eng.
Conoco Inc. (Conoco) S. E. Jacobs	Jim R. Svenvold
Farmers Union Central Exchange Incorporated (CENEX) J. A. Snider	Lorne E. Brown
Petroleum Producer Group (The Producer Group) J. B. Ballem, Q.C.	
Alberta Petroleum Marketing Commission (APMC) W. M. Moreland	
Northridge Petroleum Marketing Inc. (Northridge) A. J. Pourbaix	
CanPet Marketing Ltd. (CanPet) B. J. Foster Mr. Stephens	
Energy Resources Conservation Board staff M. Bruni R. Heggie K. Johnston C. Bennett S. Lee, P.Eng. K. Bahadur	

The following parties filed a submission but did not participate in the hearing:

Small Explorers and Producers Association of Canada (SEPAC)
Canadian Petroleum Association (CPA)
Brinkerhoff Resources Inc.
Chauvco Resources Ltd.
The Free Alberta Group
Alberta Culture & Multiculturalism

1.3 Amendments to the Application

Following the hearing, Bow River requested the following amendments be made to its application:

- tie in the proposed pipeline to Murphy's existing Milk River Station in Lsd 8-21-2-16 W4M,
- delete the portion of the proposed pipeline from Lsd 16-18-2-16 W4M to Lsd 16-7-1-16 W4M,
- delete the proposed 1270-kW pump station in Lsd 16-18-2-16 W4M near Milk River, and
- construct a 3.5-km pipeline from Lsd 16-18-2-16 W4M to Lsd 8-21-2-16 W4M.

The Board notes that the proposed Northern pipeline from Lsd 16-7-1-16 W4M to the Canada/U.S. border would no longer be necessary and that Northern has withdrawn its application from the National Energy Board (NEB).

The Board also notes that Murphy has subsequently expressed support for the amended Bow River application and has amended its own application to the NEB to expand its existing Milk River Station facilities and pipeline to accommodate Bow River's proposed tie-in.

The Board believes the alignment of the amended portion of the pipeline to be the only new area of concern raised by Bow River's amendment that was not previously considered at the hearing. Comments on this aspect were solicited from all affected landowners and registered interveners, and were considered together with the evidence presented at the hearing.

2 BACKGROUND

At the present time, Bow River, Home, and Murphy operate pipeline segments which together comprise a system that transports crude oil to the Montana border. Bow River operates an extensive gathering and trunk-line system throughout east-central and southern Alberta. Prior to 1985, its system moved crude oil from Chin Coulee to Interprovincial Pipe Lines Ltd. (IPL) at Hardisty to the north.

In February 1985, Bow River applied (Application 850027) to the ERCB requesting permission to reverse the flow of the southern portion (Fincastle-south) of its existing line. This reversal would then feed a proposed expansion between Chin Coulee and Legend and would tie in to Home's Manyberries system at Legend.

At Legend, Manyberries light oil would be combined or batched with heavy volumes from the Bow River system. These volumes would flow through Home's line into Murphy's pipeline system at Milk River for transport to CENEX's Blue Sky pipeline in Montana.

Murphy intervened at the 1985 Bow River hearing based on its competing proposal before the NEB. The proposal called for the construction of a 45-km pipeline and associated facilities between Wrentham and Murphy's Milk River terminal. Murphy requested the ERCB to direct Bow River to extend its reversal to a point in the Wrentham area, where the Bow River system would connect with

Murphy's proposed line. The ERCB took the position that it did not have jurisdiction to direct changes to the existing Bow River system and therefore could not consider Murphy's request.

The NEB approved Murphy's application in March 1985 by granting a Certificate of Public Convenience and Necessity (OC-36). The ERCB approved Bow River's application of February 1985 (Decision Report D 85-2), notwithstanding the NEB's approval of Murphy's facilities.

Bow River's Chin Coulee-to-Legend pipeline was built, while Murphy's proposal did not proceed. The above describes the events that transpired to the time of Bow River's current application to the ERCB.

During the course of the November 1991 hearing, Murphy submitted that the Board does not have the jurisdiction to deal with this application. Murphy argued that by reason of the distribution of legislative powers between the Federal Parliament and the provinces, the Province of Alberta does not have the constitutional jurisdiction to empower the Board to entertain an application for the construction and operation of a pipeline, the purpose of which is to allow for the export of oil to the U.S. The Board heard argument from Murphy and Bow River on this issue, while none of the other parties took a position. The Board reserved its decision on the jurisdictional issue at the time of the hearing.

Concurrent with Bow River's application to the ERCB for the proposed Fincastle Station-to-Montana loop, Murphy applied to the NEB for a similar pipeline. Subsequently, Murphy reached agreement with Bow River to combine both projects by tying in Bow River's proposed line to Murphy's existing line at Milk River. Murphy has since reapplied to the NEB to expand its facilities between Milk River and the U.S. border, and has withdrawn its intervention in Bow River's application before the ERCB. Consequently, the Board does not intend to address the jurisdictional issue raised by Murphy.

2.1 Responses of Interveners and Landowners to the Amended Application

The amended route traverses five quarter sections of land and the affected landowners have consented to the alignment.

Conoco and CanPet both expressed support for the amended application.

Home expressed concern that Bow River's proposed amendment could result in severe prorationing on both Bow River's proposed pipeline and on Home's existing pipeline, if the NEB does not approve Murphy's proposed loop or if there is a delay in the NEB approval.

Home argued that until the NEB has approved Murphy's proposed loop, the need for Bow River's proposed pipeline cannot be demonstrated.

Home further argued that Bow River's proposed tie-in to Murphy's Milk River system emphasizes the direct competition between Bow River's proposed pipeline and Home's existing pipeline.

Home submitted that if a permit were to be granted, it should be conditioned such that Bow River would be required to

(a) continue to permit heavy oil to flow from Chin Coulee to Legend,
(b) post a competitive tariff for such heavy oil movements, and
(c) install only that horsepower which has been demonstrated to be necessary.

Although it was not in response to Bow River's amendment, per se, Anderson withdrew its objections respecting tariff increases and quality dilution of Manyberries light oil.

3 ISSUES

The Board believes that the issues relevant to the application are

- the need for the pipeline,
- possibility for Manyberries light crude dislocation,
- alternative transportation systems,
- costs and benefits of the proposed pipeline, and
- the mechanical design and routing of the proposed pipeline.

4 NEED FOR THE PIPELINE

4.1 Views of the Applicant

Bow River stated that its proposed pipeline constitutes an economic, orderly, and efficient development in the public interest. This argument was supported by reference to the market requirements for Bow River-type heavy crude oil, the available supply of Bow River crude oil, and the requirement for additional capacity.

4.1.1 Market Requirements

Bow River developed its pipeline application on the basis of Conoco's additional feedstock requirements for its refinery at Billings, Montana. A new coker with a capacity of 8000 cubic metres per day (m^3/d) of heavy crude oil is due to begin operation in May 1992. The initial required volume of Bow River crude oil is 3200 m^3/d. Coupled with an additional demand by CENEX of 600 m^3/d, the total additional volumes required in Montana are 3800 m^3/d.

Bow River stated that approximately 1600 to 2000 m^3/d of heavy crude oil is currently moving through its Chin Coulee-to-Legend extension, to Home's Manyberries pipeline. In order to meet the incremental Montana demand, a new pipeline must be built. Although Cold Lake bitumen could become an alternative source of supply for the Montana market, Bow River stated that its pipeline system is the only one with ready access to the necessary reserves to fill the incremental demand. As well, Bow River crude oil currently enjoys a price advantage over other U.S. heavy oil sources available to Montana refineries. Bow River stated that alternative U.S. supplies available to Conoco are primarily Wyoming heavy sour grades as well as Wyoming asphaltic crude oils. Increased access, though, could only come about through additional pipeline capacity into Montana from these Wyoming sources.

Bow River presented a letter of agreement which outlined the substance of the commitment with Conoco. In that letter, it confirmed that Conoco would transport its volumes of Bow River crude oil through the proposed system exclusively, although Bow River stated that this does not constitute a minimum throughput guarantee.

Bow River expressed a high degree of confidence that the emerging Montana market could be a valuable additional customer to Bow River producers.

4.1.2 Available Supply

Bow River stated that reserves in the area are more than adequate to supply both the emerging Montana market (Hays-south) and the traditional load on IPL (Hays-north). As well, Bow River stated that its project, coupled with both the Husky Upgrader and recently announced royalty holidays by the Government of Alberta, would stimulate drilling in the Bow River area, as necessary, to respond to new opportunities.

4.1.3 The Requirement for Additional Pipeline Capacity

The existing system (Bow River/Home/Murphy system) to Montana is operating at capacity and new capacity is necessary to accommodate any new markets. Further, Bow River suggested that its proposal is timely in view of IPL's apportionment problems for oil destined to eastern markets. If IPL's problems continue beyond the short term, Bow River area producers could experience shut-in rates in the order of 30 per cent. Therefore, increased access to Montana markets would help to alleviate such capacity constraints.

Bow River's proposal takes into account the possibility of future growth in the Montana market. In Bow River's opinion, the proposed pipeline's capacity of approximately 6600 m^3/d, given the implicit installation of sufficient backup pumping power, satisfies Conoco's initial requirements and allows for the possibility of future growth.

Bow River stated that its proposal is the most direct and efficient method for adding pipeline capacity to Montana. Bow River estimated the total capital costs for the Fincastle-to-Montana system, as originally planned, to be $11 500 000. The revised application would eliminate one pump station, would shorten the originally proposed pipeline by 7.9 km, and would result in a lower capital cost. Bow River further stated that information submitted on proposed tariffs confirmed considerable economies over the use of the existing system.

The existing system would not become redundant if the application is approved. Bow River stated that, as the Home-Manyberries pipeline was initially constructed to serve producers of Manyberries crude oil, this would still be the case in the event that Bow River's proposed pipeline is built. As well, in Bow River's opinion, Murphy would continue to operate its truck terminal and feeder pipelines at Milk River, despite the development of Bow River's new pipeline.

A final point that Bow River emphasized is that Home can adjust tariffs in order to keep its existing system competitive.

4.2 Views of the Interveners

Conoco is spending approximately $150 million U.S. in its Billings refinery in order to be able to process some 8000 m^3/d of Canadian and Wyoming heavy and/or sour crude oils. The anticipated mix of these crude oil is

- 3200 m^3/d of Bow River heavy crude oil,
- 2400 m^3/d of Cold Lake bitumen, and
- 2400 m^3/d of Wyoming heavy sour crude oil.

Conoco advised that it was prepared to support another company's construction of a system which could ultimately deliver up to 8000 m^3/d. Conoco explained that a new system would be required to

- have capacity for future market growth,
- have the flexibility to divert volumes elsewhere during refinery turnarounds,
- have access to many shippers and potential suppliers,
- maintain a tariff which keeps the price of the crude oil competitive, in both the short and long term, and
- be in operation by 1 May 1992.

Conoco noted that meetings were held with Home, Murphy, and Bow River in January and February 1991, where each company was encouraged to submit a proposal, or a joint proposal, for additional pipeline capacity. Conoco explained that it received proposals from Bow River and Murphy, and that it judged Bow River's proposal to be superior.

Home emphasized that it supported the economic, orderly, and efficient development of facilities to serve a new market, provided the utilization of existing facilities is fully considered and that the new markets can be clearly identified. Home requested that the Board should consider all reasonable alternatives, whether or not they are applied for, when assessing this application.

In Home's testimony, the likelihood that existing facilities would be rendered redundant is virtually guaranteed if the Board approves the Bow River application. Home considered the Bow River proposal to be a "bypass system" because pumping power would be installed in excess of what would reasonably be required for an incremental market of 3800 m^3/d. Home concluded, therefore, that Bow River hopes to capture the market for transporting all heavy crude oils to Montana.

Home also questioned the degree of commitment between Bow River and Conoco because there appeared to be no written assurance that any volumes of crude oil would be taken from the proposed system, noting that Bow River declined the offer of a throughput agreement. Therefore, the full financial risk of this project appears to remain in Alberta. As well, the lack of any real market commitment would allow Conoco to achieve its objectives of supply diversity and price competition between Cold Lake, Wyoming sour, and Bow River streams.

Further, it was Home's view that need and necessity, for Bow River's proposal specifically, could not be demonstrated until the NEB has certificated Murphy's proposed loop from Milk River to the U.S. border. Therefore, Home requested that any ERCB approval should be conditioned accordingly.

CENEX would support any proposal that would provide additional capacity. CENEX currently holds contracts to import 1750 m^3/d of Canadian heavy crude oil through the existing Bow River pipeline system. Owing to pipeline constraints on the present Bow River/Home/Murphy system, CENEX is able to ship only 1300 to 1400 m^3/d. CENEX stated that if new capacity is made available, it would likely increase its take to 2400 m^3/d.

CENEX suggested that the Board should not prevent additional pipeline capacity to Montana merely to provide a guarantee of perpetual use of existing pipelines. CENEX stated that if pipelines become uneconomic, for example through field production declines, it should not fall to the Board to provide regulatory protection to those pipelines. Furthermore, CENEX speculated that Home has had a good return on its $10 million investment in the Manyberries system. CENEX stated that it alone has paid to Home $17.9 million in tariffs for the transportation of both Bow River heavy and CENEX's share (70 to 80 per cent) of Manyberries total production.

The Producer Group, APMC, and Northridge did not endorse one proposal over the other. Rather, Alberta should drive ahead with one of the proposals. They strongly urged that the matter be resolved in favour of new capacity as expeditiously as possible, so as not to jeopardize the new market.

Anderson took no position on the issue to add pipeline capacity to Montana in relation to heavy oil volumes. It emphasized it is a very active explorer and producer generally supportive of new market initiatives and a strong proponent of a free market system for crude oil sales.

4.3 Views of the Board

The Board is satisfied the essential elements that support the need for additional pipeline capacity are present. First, the Board is convinced that Montana refineries offer reasonably secure marketing opportunities for Alberta heavy crude oil producers. In the near term, the immediate requirements of Conoco and CENEX would boost Alberta heavy production by a minimum of 3800 m^3/d. This would likely increase over the longer term as Wyoming reserves are depleted. As well, if Conoco's optimism is well founded, Montana refineries will expand their market area and, ultimately, require additional Alberta heavy crude oil.

Second, there is no doubt about the willingness of Bow River producers to supply heavy crude oil to an expanded system. The Producer Group stated their willingness to provide such incremental production, and enough reserves appear to be available over the long term to support the market.

Finally, none of the participants at the hearing took issue with the need for additional capacity if the incremental Montana demand is to be made accessible to Bow River producers. Neither does the Board question this reality. Thus, all of the market elements that would underpin Bow River's proposal appear to be intact: the existence of sufficient reserves that producers can sell to willing consumers if pipeline capacity can be expanded.

The Board believes that conditioning any approval issued by the ERCB on parallel NEB approval of Murphy's facilities expansion, as requested by Home, is unnecessary. In the event that NEB approval of Murphy's application were delayed or denied, the ERCB believes that an alternative proposal along the same general route and involving facilities in reasonable proximity to Milk River would eventually proceed. Thus, the Board believes that since an alternative corridor, entirely removed from Milk River, is not even being contemplated by anyone presently, there is little risk that new facilities upstream of Milk River would go underutilized for long.

The Board's view of Home's request to consider the use of existing facilities and other alternatives is dealt with in Section 6.

5 MANYBERRIES LIGHT CRUDE DISLOCATION

5.1 Views of the Applicant

5.1.1 Tariff Effects

Bow River agreed that its proposal could lead to reduced throughput on the Home-Manyberries system. Thus, any resultant higher operating costs per unit of throughput could result in higher tariffs if Home were unable or unwilling to absorb such cost increases. Bow River indicated, however, that the current tariff is close to the cost of trucking the crude oil. Therefore, there is a ceiling on the tariff Home could charge and still remain competitive.

Bow River argued that its proposed new line would induce competition among pipeline owners in the region, to the benefit of producers. This view suggests that there is sufficient latitude in current tariffs to permit downward adjustments in response to competitive forces. Thus, it would be in Home's interest to keep its system competitive by adjusting tariffs such that the cost to move oil to Montana on the existing system would be more in line with the tariff on the proposed new system.

Bow River suggested that, given the volumes of crude oils that have moved and are currently moving through Home's line (2880 m^3/d), capital costs should have been recovered by this time. This would support the contention that Home could reduce tariffs and remain viable.

5.1.2 Price Degradation

Bow River acknowledged that commingling Bow River heavy crude oils with Manyberries light crude oils at the Legend station has led to the degradation of the overall quality of the Manyberries stream. Bow River also agreed that if this continues it is possible that future Manyberries production will receive the price equivalent of heavy crude oil.

While recognizing the inherent difficulties faced by Manyberries producers, Bow River felt that its proposal would not exacerbate the problem. Furthermore, Bow River noted that Home has the ability to batch light crude oils on its system but chooses not to because of problems downstream, particularly in the CENEX pipeline system in Montana, which does not have the ability to batch crude oils.

Bow River suggested that its proposal, coupled with the Husky upgrader in Lloydminster, should reduce the current light/heavy crude oil price differential. In Bow River's opinion, the size of the current price differential is due in part to constraints on market access for Alberta heavy crude oils. The two aforementioned projects would increase overall demand for heavy crude oil, thus leading to a reduction in the size of the differential. Therefore, the potential price degradation impact on Manyberries producers would be mitigated to some extent, perhaps in the order of \$10/m^3.

5.1.3 Proposed Solutions

Bow River suggested a number of options that could alleviate the problems faced by Manyberries producers:

- Reverse the Chin Coulee-to-Legend extension and then transport volumes to the new proposed pipeline. From this point oil could be batched for delivery to Montana.

- Batch oil on the existing Home/Murphy and CENEX system.

- Return the Home-Manyberries system to its original use as a transporter of light crude oil.

- Truck Manyberries production directly to Montana refiners and pipelines. Bow River noted that this option would require a clear contract with the parties involved in order to make it viable.

5.2 Views of the Interveners

Anderson advised that since the Home-Manyberries pipeline was installed in 1985, Manyberries oil production increased from 430 m^3/d to as high as 600 m^3/d and that at least seven waterflood projects are either in the planning, development, or implementation stage. These and other development activities are very sensitive to small changes in economic conditions, particularly the price of oil. Anderson was concerned that Manyberries producers may be forced to accept a heavy crude oil price for their light crude oil production if no solution is found to the existing degradation of the light stream. As a result of discussions between Bow River and the producers subsequent to the hearing, however, Anderson was satisfied that its concerns were being addressed and requested that its intervention be withdrawn.

CENEX acknowledged the potential for price degradation of the Manyberries stream. CENEX stated that it buys 70 to 80 per cent of the available Manyberries crude oil and that it has undergone a quality deterioration since 1985, when Bow River tied its Chin Coulee extension into the Home system at Legend. The potential for new heavy volumes moving south would further degrade the Manyberries stream as there is no capacity to segregate the stream south of the international border. CENEX noted, however, that batching facilities could be put in place south of the border on its Blue Sky pipeline. This decision would depend on the costs, and the ability to commingle a segregated Manyberries stream with a stream of similar quality produced and transported downstream of the CENEX pipeline.

CENEX would be willing to continue the current arrangement with Manyberries producers so long as the delivered product is distinguishable from heavy crude oil. CENEX emphasized that a commercial solution can be found to this problem, perhaps by segregating the Manyberries stream. In any case, CENEX did not feel the Board should assign undue weight to potential impacts on Manyberries producers.

Home noted that it currently has the capability to batch the Manyberries stream; however, it is not done because of problems downstream of Home's facilities.

Home also pointed out that CENEX will remain a committed buyer of the Manyberries light stream only if it is identifiable at the refinery gate. Approving the Bow River application would jeopardize CENEX's commitment and would reduce the price to Manyberries producers, with a consequent negative impact on the Alberta public as the royalty interest holder.

An expansion of the existing system, in Home's view, would be economic, orderly, and efficient because it, in part, assures a solution to the Manyberries problem. However, Home stated that if Bow

River's application is approved it should be conditioned such that Bow River must continue to permit oil to flow from Chin Coulee to Legend. This, in Home's submission, would ensure that the benefits of competition would be more widely spread. Home asked that any permit be conditioned such that Bow River must post a competitive tariff on volumes moving from Chin Coulee to Legend.

5.3 Views of the Board

The Board is encouraged by the fact that Anderson, Bow River, and Murphy appear confident that reasonable efforts could allow Manyberries light crude oil to continue to be sold as a light product rather than be discounted to a heavy crude oil price. Since Anderson withdrew its intervention, commingling and price degradation of Manyberries light crude oil are no longer considered to be issues germane to this application.

The Board does not believe a condition that would require a continuation of the direction of flow from Chin Coulee to Legend is desirable. The Board sees no compelling reason to require such a condition since producers may, in fact, benefit from a reversal of that pipeline. Neither does the Board consider it appropriate to condition the permit on matters related to tariffs. Since it appears both facilities can remain viable it believes tariffs should be determined through normal market forces.

6 ALTERNATIVE TRANSPORTATION SYSTEMS

6.1 Views of the Applicant

6.1.1 Existing Bow River/Home/Murphy System

According to Bow River, the existing system's pumping and measurement infrastructure would have to be upgraded and the pipeline system would have to be looped, in order to augment capacity sufficiently to satisfy Montana's expected requirements. Bow River estimated it would cost \$13 410 000 to deliver incremental volumes of 3800 m^3/d as well as the current volumes moving on the system.

Bow River also considered the costs to upgrade the existing system to equal the total capacity of its proposal, which would allow for growth in the Montana market. The total cost of doing so was estimated to be \$13 660 000.

Furthermore, Bow River noted that higher operating costs would likely result from an upgrade of the existing system, because the oil would have to flow a greater distance through two additional pumping stations, when compared to its proposal.

6.2 Views of the Interveners

Home suggested the existing pipeline system could be economically expanded if the parties choose to cooperate, but noted Bow River's reluctance to pursue this alternative.

Home estimated the cost to expand the existing system to transport an incremental 3800 m^3/d would be \$11 460 000. This figure is less than Bow River's estimated cost to construct its 6600 m^3/d facilities. Assuming that the Bow River and Murphy systems are operated at equal cost and efficiencies, and are depreciated in a manner similar to Home's facilities, the tariff under this expansion would be $\$3.33/m^3$.

To proceed with such a plan, Home would require a throughput agreement or some other guarantee to cover the cost of service for the new construction. Home would also require the full cooperation of Bow River and Murphy as operators of the interconnecting pipelines. Home recommended that if the Board does not deny the application outright, then issuance of its decision should be deferred for several months, to allow the parties to continue to negotiate. The parties, in this case, are the pipeline companies and the two Montana refineries, all of whom have a vested interest in resolving the matter cooperatively. In Home's view, the complex issues involved with this application are more important than the timing requirements of Conoco.

6.3 Views of the Board

The Board is satisfied that all parties have had the opportunity to participate in the negotiations leading up to the application. This is particularly evident by the agreement reached between Bow River and Murphy, and by the steps that have been taken towards resolving Anderson's particular problems.

The Board also notes that Conoco and The Producer Group, being the principal buyer and seller, respectively, support the proposal and are anxious to proceed. The Board is satisfied that a delay in completing the line may have a detrimental effect on capturing the market.

In the Board's opinion, deferring its decision for several months to allow for further negotiations would serve no purpose. Home's alternative, which was advanced more as a possibility than as a developed plan, does not appear to offer any advantages by way of costs, timing, or efficiency of crude oil movement, over the Bow River proposal, much less the order of benefits that would warrant deferring the Board's decision.

The Board believes the Bow River proposal is suitable.

7 COSTS AND BENEFITS OF PROPOSED PIPELINE

7.1 Views of the Applicant

As noted earlier, Bow River felt that its proposed tariffs would be competitive and economic because they are acceptable to both the shippers and buyers of the crude oil. Bow River also suggested that competition from its proposed line would cause Home to adjust its tariffs in order to keep its system viable.

Bow River also outlined a number of other direct and indirect economic benefits associated with its proposed pipeline:

- The new proposal would offer north-south market flexibility to Bow River producers, which would be particularly valuable when faced with IPL apportionment. As well, additional capacity would be available into the IPL system as Bow River production expands. This flexibility would also enhance the long-term financial stability of producers.

- The price of heavy crude oil would likely rise because of this proposal together with the Husky Upgrader in Lloydminster.
- Drilling activity in the Bow River pipeline corridor would be stimulated by this proposed expansion.
- The agriculture and service sectors in the vicinity of the proposed pipeline would benefit. The landowners along the right of way alone would receive a $300 000 to $400 000 benefit.

7.2 Views of the Interveners

Home suggested that it would be naive to believe the tariffs mentioned by Bow River for their proposal are firm since, in its opinion, there are no related contractual commitments between Bow River and Conoco.

Home also suggested that the financial risk accepted by Bow River because of the rejection of a market commitment reveals a total disregard for the interests of producers, the royalty holders, and the public of Alberta. There is no assurance that Bow River would not recover unanticipated losses through activities such as cross-subsidization from other system toll payers.

Because of these negative impacts, Home stated that the Bow River application is not in the broad public interest of the people of Alberta and should, therefore, be denied.

7.3 Views of the Board

The Board agrees that there are significant benefits to be gained by expanding Alberta's heavy oil market into Montana. The marketing arrangements developed between Bow River and Conoco appear to offer immediate opportunities that may grow, over time, to the benefit of all involved.

In the Board's view, the risk of inordinate toll increases as alluded to by Home is not large and, in any event, avenues of appeal are available to producers if tolls are believed to be unfair.

8 MECHANICAL DESIGN AND ROUTING OF PROPOSED PIPELINE

8.1 Views of the Applicant

Bow River stated that to ensure the project could proceed without delay, it has already purchased all required pipe materials and, with the exception of one occupant on Crown land, has acquired all necessary rights of way for construction. Bow River indicated that the proposed pipeline route would have no unusual environmental concerns, that the major water crossings would present no special concerns, and that the major highway and railway crossings would not result in any inconvenience to the public.

In response to questions by Home respecting pipeline capacities, Bow River stated that in its project development, it had investigated using a 219.1-mm OD line between Chin Coulee and Milk River and had found it inadequate. Consequently, Bow River chose the 273.1-mm OD line. Bow River believed that this would provide the required capacity to serve the incremental Montana market, and also allow for future market growth without additional looping or booster stations.

In response to Home's concern respecting excess pump horsepower, Bow River argued that with a Montana market on one end of the system and hundreds of Alberta producers on the other end, it would be prudent for the pipeline operator to install some backup horsepower. Bow River's approach would be to install a spare unit at each station to ensure that it would continue pumping if one unit went down. In addition to reliability factors, Bow River submitted that the proposed system is not oversized because of the potential for market growth to the south. It further argued that neither Home nor the Board should get involved in the design of another party's facilities.

Bow River stated that the proposed pipeline would be designed to include leak detection and control systems to comply with the latest edition of the Canadian Petroleum Association (CPA) Recommended Practice. Bow River claimed that the data retrieval and volume balance control centre, which would be located at the existing Koch Industries control centre in Wichita, Kansas, would be able to shut down the pipeline and pump systems immediately, and isolate segments of the system if a problem were detected. Pipeline operating personnel would be located in Brooks, Alberta, and would be able to communicate with the control centre in Wichita to view the supervisory control system screens and to respond to repair needs or emergencies.

8.2 Views of the Interveners

The interveners did not express concern about the proposed pipeline route or about Bow River's ability to comply with the CPA Recommended Practice for leak prevention and detection. Neither did the interveners question the technical aspects of the proposed pipeline and pump stations, except for Home, which was concerned about the oversizing of pump stations.

Home argued that the proposed 1270 kW per station would be substantially greater than required for a 3200 m^3/d market. According to Home's calculations, the power required to pump this volume would be only 250 kW at each station. Even to deliver 6600 m^3/d, which would be the estimated maximum possible flow under the proposed system configuration, the power requirements would be about 1000 kW at each location. Home submitted that such an oversizing of the proposed project vis-a-vis the incremental market would threaten the viability of existing facilities.

Home acknowledged that the proposed 273.1-mm OD pipeline would be in the public interest owing to lower operating costs, although it believed a 219.1-mm OD pipeline would be adequate.

With respect to the possibility of looping the existing Manyberries system, Home questioned the accuracy of Bow River's cost estimate for such an alternative. While it agreed with Bow River's pipeline cost estimate, Home argued that the incremental pumping power was overstated, thus resulting in a higher total estimated cost.

Home submitted that although it was not presently developing a proposal to loop its Manyberries pipeline, new facilities should be strictly sized to fit the remaining proven incremental demand. Home requested that if the application were to be approved, it should be conditioned to limit the pumping power to 250 kW at each station for a total of 500 kW, consistent with Home's calculated requirements for the delivery of 3200 m^3/d.

Conoco supported Bow River's proposal as it stands and stated that if a smaller pipeline were built, it would be under apportionment as soon as it became operational. It would provide no flexibility for Conoco or CENEX to ship additional volumes. Conoco also suggested that Exxon, which operates a similar type of refinery in Billings, might also have an interest in Bow River crude oil.

The Producer Group indicated that the Bow River application was a complete application and that, from a technical point of view, the pipeline project could be termed "routine" and "run of the mill". Therefore, there was no real concern with the physical aspect of the line or its construction.

8.3 Views of the Board

The Board finds the technical specifications, routing and alignment to be acceptable as submitted by Bow River. Although the size of pipe and associated pumping capacity appear large in view of immediate requirements, such planning seems prudent in view of potential market developments and improved operating reliability. Despite the oversizing factor, evidence submitted on probable tariffs appears reasonable.

On the basis of the evidence and arguments presented, the Board finds no need to require alternative specifications for the proposed pipeline.

9 DECISION

After considering all the evidence noted and filed with the Board, both in the course of the hearing as well as the modified application, the Board is prepared to approve the application as amended of Bow River Pipelines Ltd. subject to receipt of the approval of the Minister of the Environment respecting environmental matters.

DATED at Calgary, Alberta, on 10 February 1992.

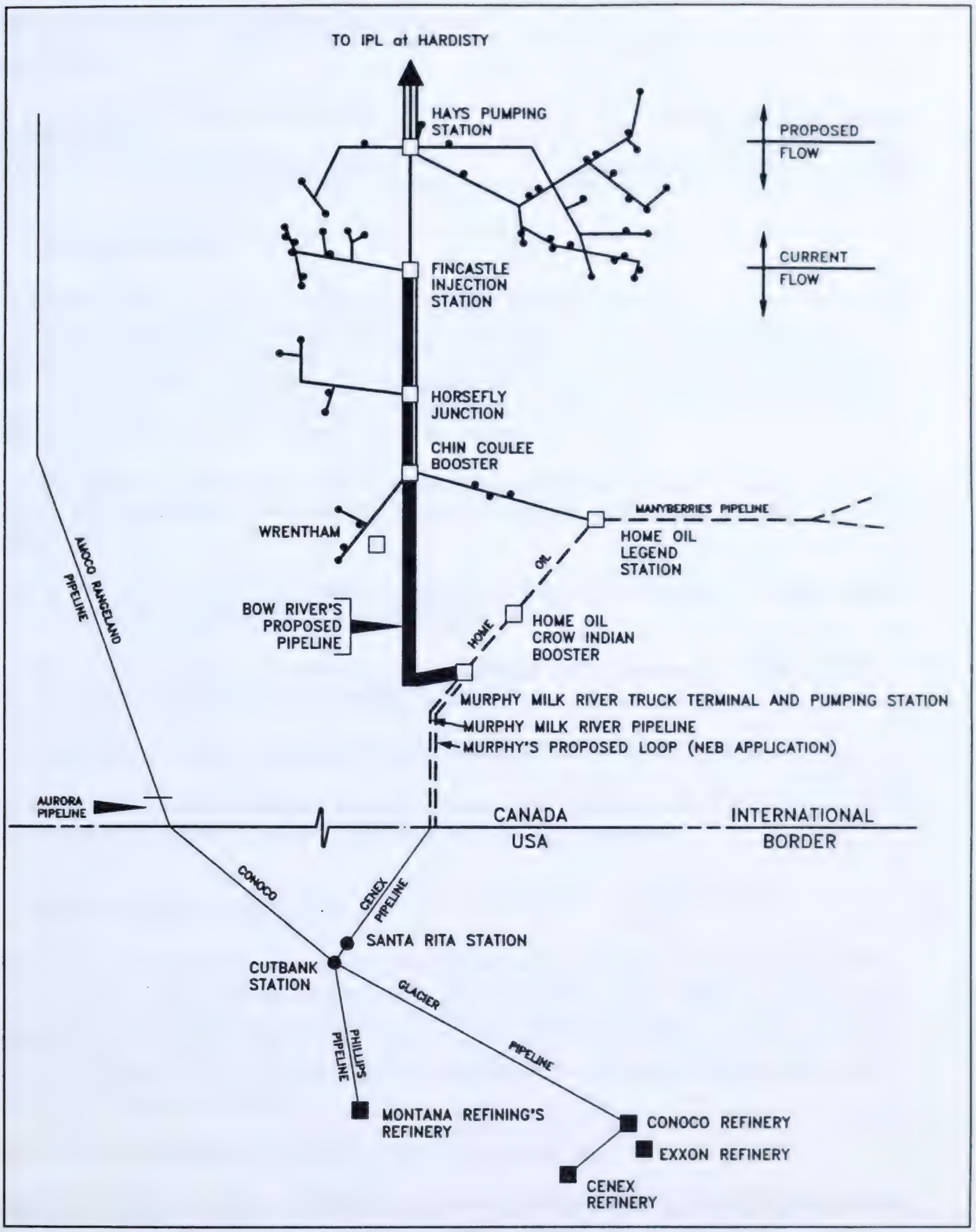
ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

RG Evans

R. G. Evans, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Board Member



PROPOSED FINCASTLE STATION TO MONTANA LOOP

Application No. 911262

Bow River Pipe Lines Ltd.

D 91-15

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR WELL LICENCES
OKOTOKS FIELD
CANADIAN OCCIDENTAL PETROLEUM LTD.

Memorandum of Decision
Pre-Hearing Meeting
Applications No. 910253 and 911089

---

1 INTRODUCTION

On 18 February 1992, the Energy Resources Conservation Board (the Board), as set out in a notice of re-scheduling of hearing issued from the office of the Board on 2 January 1992, had intended to commence the hearing of Applications No. 910253 and 911089 submitted by Canadian Occidental Petroleum Ltd. (Canadian Occidental). The applications are for licences for two wells to be drilled from a surface location in legal subdivision 6 of section 18, township 22, range 28, west of the 4th meridian, to evaluate and obtain production from the Wabamun Formation.

Prior to the opening of the hearing the Board received a suggestion that it may be appropriate to defer the hearing of the applications and review the proposed timing and procedure for the consideration of the applications.

In order to afford all parties the opportunity to state their position on these matters, the Board decided that a pre-hearing meeting would be held on 18 February 1992.

The panel members presiding at the meeting were J. P. Prince, Ph.D., chairman, B. F. Bietz, Ph.D., P.Biol., R. G. Evans, P.Eng., and T. L. Guidotti, M.D., M.P.H.

The names of the participants who registered at the meeting are shown on the attached list.

At the outset of the meeting Canadian Occidental requested that Application No. 910253 for a well licence for the well, CDNOXY ET AL OKOTOKS 6-18-22-28, be withdrawn.

2 VIEWS OF THE APPLICANT

Canadian Occidental believes it was apparent that the hearing of the proposed well licence application would have generic implications in relation to sour gas development. Accordingly, it was requesting that the Board implement special procedures in the hearing of the application. Specifically, Canadian Occidental proposed that the application be heard in two phases. The first phase would address any generic issues raised by the interveners, while the second phase would address matters pertaining to the specific well licence application.

Canadian Occidental requested that the two phases run consecutively.

Respecting local intervener status and funding, Canadian Occidental urged all parties to file application in accordance with the Board's Local Interveners' Costs Regulation, with the exception of Calgary Health Services (Calgary Health), which Canadian Occidental believed should not qualify.

3 VIEWS OF THE INTERVENERS

The Over the Hill Community Group (Over the Hill) stated that it opposed the process suggested by Canadian Occidental. It submitted that a three-phase hearing which would not be held consecutively may be desirable. The first phase would address health and safety issues. Phase Two would address land-use constraints and production timing. Phase Three would hear any particular well licence.

Over the Hill requested that the Board be prepared to consider applications for local interveners' costs prior to the commencement of the hearing.

The South East Loop Residents (South East Loop) opposed Canadian Occidental's proposed procedure. South East Loop suggested that a consultative procedure between the Board and other various government agencies and jurisdictions be convened to affirm regulatory policies. Once this had been established, the hearing of the application could proceed.

Calgary Health rejected Canadian Occidental's proposal, suggesting that the Board schedule and provide for a pre-hearing conference to be attended by government agencies or bodies with an interest in the matters relating to sour gas development in the urban fringe. This would then produce a working paper reflecting a consensus of the government agencies which would provide a reference point for either a general inquiry into sour gas development in the urban fringe or for hearings related to Canadian Occidental's application.

Calgary Health submitted it would be applying to the Board for direction on the right to recover costs as a local intervener.

The City of Calgary (the City) supported a two-stage hearing, with Phase One establishing general standards. The Board could then issue a decision respecting these standards and then move to a site-specific hearing for the well licence. The City reserved the right to consider making application for local interveners' costs.

The Calgary Regional Planning Commission (Planning Commission) supported a two-phase hearing with a break between each phase. The first phase would consider setback, health, and risk questions and the second would deal with all remaining issues. The Planning Commission would also support the establishment of a consultative process and it also suggested the Board might consider a province-wide inquiry into setbacks.

Carma Developers Limited (Carma) did not support either the procedures proposed by Canadian Occidental or a two-phase hearing. Carma requested that the Board establish a consultative process to reach a consensus from all parties on setbacks and emergency planning zones. Once standards have been agreed upon, the Board could hear the well licence application and related issues. Respecting costs, Carma submitted that whatever process was chosen, the eligibility of interveners to apply for costs should be assured.

The McKenzie Lake Community Association (McKenzie Lake) did not support Canadian Occidental's two-phase hearing. McKenzie Lake argued that it should first be established whether or not it would be affected by the standards which would be used in reviewing such applications. Once this has been determined, the process could move on to consider the application.

Frederick Joseph Ollerenshaw (Ollerenshaw) objected to the motion of Canadian Occidental to segregate the hearings as it proposed. Ollerenshaw did support a two-phase hearing which first addressed generic issues and then addressed well-specific issues. The Ollerenshaws were of the opinion that the Board should issue direction as to costs and that costs should apply to the entire proceeding regardless of its form.

Constantin and Alexander Soutzo, Genstar Land Development Company, Maalsa Investments Ltd., and 408460 Alberta Ltd. (the Soutzos) suggested that the Board first convene a hearing or inquiry with all relevant parties to address technical issues. Once this has been completed, the specific hearing on Canadian Occidental's application could proceed. Respecting costs, the Soutzos urged the Board to adjudicate on costs before any hearings resumed, regardless of the format.

Burnco Rock Products (Burnco) supported one hearing, as it believed that all issues were interrelated in such a manner that it would be inappropriate to separate them. Burnco submitted that costs should be a matter to be dealt with on a preliminary basis.

The Bow North Surface Rights Association and Chestermere Area (Bow North) requested that the group be heard as local interveners in any generic hearing.

The Castleridge, Falconridge Community Association (Castleridge-Falconridge) submitted that the Board should not proceed to consider new proposals for sour gas development until it was determined that existing facilities in close proximity to urbanized areas were safe.

4 VIEWS OF THE BOARD

In a Memorandum of Decision dated 20 June 1991, the Board decided that the applications for well licences in the Okotoks Field would be dealt with separately from the development of the Crossfield Pool, which is in close proximity to East Calgary. The reasons for that decision were conveyed in the Memorandum and so need not be repeated here. The Board continues to believe there are advantages in considering the two developments separately.

However, the health and safety issues raised by Calgary Health relate to both developments and, potentially, to all sour gas development in the Province. These issues address the appropriateness of the setback distances and emergency response planning zones established by the Board and, by implication, the models, assumptions, and procedures used to establish those parameters.

The generic nature of these issues suggests that a process allowing the participation of a broader group than is currently involved with the applications submitted by Canadian Occidental might be useful. Several participants in the meeting suggested such an approach; few, if any, participants appeared opposed to it. Therefore, the Board is prepared to organize and participate in a process that would involve the public, the industry, and appropriate departments and agencies of government.

The processing of Application No. 911089 will be deferred until further notice. Over the next few weeks, the ERCB will consider the best way to ensure broad participation in a process to consider the issues. The Board will be contacting interested parties as part of this deliberation and will ensure that all participants in the pre-hearing meeting, as well as others who may have an interest, have the opportunity to contribute to whatever process is established.

Because processing of the applications has been deferred, there may be some need to consider claims for local interveners' costs incurred to date. Any claims filed will be considered under the Board's guidelines for local interveners' costs, as set out in ERCB Guide G-31. The guide is available from the Board's Information Services Section.

DATED at Calgary, Alberta, on 12 March 1992.

ENERGY RESOURCES CONSERVATION BOARD

J.P. Prince

J. P. Prince, Ph.D.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

R. G. Evans, P.Eng.
Board Member

T. Guidotti, M.D., M.P.H.
Acting Board Member

---

* Mr. Evans and Dr. Guidotti were unavailable for signature but concur with the content and issuing of this memorandum.

PARTICIPANTS AT THE MEETING

Participants (Abbreviations Used in Report)	Representatives
Canadian Occidental Petroleum Ltd. (Canadian Occidental)	F. M. Saville R. A. Neufeld L. Stewart
Over the Hill Community Group (Over the Hill)	B. O'Ferrall B. Heatherington
South East Loop Residents (South East Loop)	C. Steele
Calgary Health Services (Calgary Health)	J. R. Paulus
The City of Calgary (the City)	C. R. Meyers
Calgary Regional Planning Commission (Planning Commission)	J. Rusling
Carma Developers Limited (Carma)	J. Perraton
McKenzie Lake Community Association (McKenzie Lake)	J. Broadley
Ollerenshaw Ranch Management (Ollerenshaw)	D. Edie
Constantin and Alexander Soutzo Genstar Land Development Company Maalsa Investments Ltd. 408460 Alberta Ltd. (the Soutzos)	L. MacLachlan
Burnco Rock Products Limited (Burnco)	P. Pastewke
Bow North Surface Rights Association and Chestermere Area (Bow North)	P. Edwards
Energy Resources Conservation Board	M. J. Bruni N. F. Lord M. Craig

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SIGNALTA RESOURCES LIMITED COMMON CARRIER SUGDEN GRAND RAPIDS H AND COLONY UNDEFINED POOLS

Decision Report D 92-1
Application 910454

1 INTRODUCTION

1.1 Application

Signalta Resources Limited applied,

- under section 37 of the Oil and Gas Conservation Act (the Act), for an order declaring Amoco Canada Petroleum Company Ltd. to be a common carrier of gas produced from the Sugden Grand Rapids H Pool (the H Pool) and from an undefined Colony pool, through pipelines extending from a well located in legal subdivision 6 of section 8, township 63, range 9, west of the 4th meridian (Lsd 6-8-63-9 W4M) (the 6-8 well), to a compressor station located in Lsd 11-7-63-8 W4M, and

- under section 45 of the Act, for the common carrier order to be effective as of 1 April 1991.

Amoco Canada Petroleum Company Ltd. filed a submission opposing the application.

The application was considered at a public hearing commencing 18 December 1991 before Board Members F. J. Mink, P.Eng., N. G. Berndtsson, P.Eng., and Acting Board Member K. G. Sharp, P.Eng.

The following table lists those who appeared at the hearing and the abbreviations used in this report.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Signalta Resources Limited (Signalta) J. B. McCashin	H. M. Sorensen, P.Eng. Y. Halim-Dihardja, P.Geol. J. R. Stueck, P.Eng.
Amoco Canada Petroleum Company Ltd. (Amoco) R. G. Panchuk	G. Kinney L. G. Rodwell, P.Eng. V. P. Rodych, P.Eng.
Energy Resources Conservation Board staff C.J.C. Page G. J. Dodd, P.Geol. P. Kahler K. Fisher T. K. Wong, P.Geol.	

1.2 Background

Signalta drilled a well in Lsd 8-17-63-9 W4M (the 8-17 well) in December 1990, encountering gas reserves in the upper and lower Colony sands. Deliverability tests conducted at the well in January 1991 showed the absolute open flow potential of the upper and lower Colony pools to be 100 thousand cubic metres per day (10^3 m^3/d) and 102 × 10^3 m^3/d, respectively. At the time of the hearing, the 8-17 well was not tied in to any gathering system.

The H Pool is a non-associated sweet gas pool currently interpreted by the Board as underlying some 14 sections, as shown on the attached figure. The 6-8 well, licensed by Amoco, is presently the only well producing from the pool. The well began producing in July 1988. Cumulative production to 31 December 1991 totalled 65.5 million (10^6) m^3, with the production rate averaging 81 × 10^3 m^3/d during December 1991.

Gas from the 6-8 well is transported to a compressor station in Lsd 11-7-63-8 W4M, operated by Ranger Oil Limited (Ranger), through two Amoco pipelines: a 114.3-millimetre (mm) outside diameter (OD) pipeline extending from the 6-8 well to a well in Lsd 5-13-63-9 W4M (the 5-13 well), and a 219.1-mm OD pipeline extending from the 5-13 well to the compressor station (see figure).

2 ISSUES

The Board considers the issues to be

- the continuity of the pools encountered by the 8-17 well,
- the need for the common carrier order, and
- the details of the common carrier order, if issued.

3 CONTINUITY OF POOLS ENCOUNTERED BY THE 8-17 WELL

3.1 Views of the Applicant

Signalta argued that log and pressure data show that the upper Colony reservoir encountered by the 8-17 well is part of the same pool penetrated by the 6-8 well and wells in Lsd 7-18-63-9 W4M and Lsd 7-24-63-10 W4M. As part of the evidence supporting its interpretation, the applicant submitted the results of a surface pressure measurement taken on 8 January 1991, and a bottom-hole static gradient test conducted on 7 April 1991, which showed the pressure of the upper Colony sand at the 8-17 well to be 1773 and 1697 kilopascals (kPa), respectively. Signalta observed that the initial pressure of the upper Colony sand in the area is about 2500 kPa. It concluded that the upper Colony reserves associated with the 8-17 well were in the same pool as those encountered by the 6-8 well and are being drained by production from that well.

The applicant noted that the lower Colony reservoir encountered by the 8-17 well is not present in adjacent wells, and that the pressure of this reservoir is between 2500 and 2600 kPa, consistent with the expected, undrained initial pressure of the sand in the area.

3.2 Views of Amoco

Amoco stated that its overall interpretation of the upper Colony pool differed from that presented by Signalta, but that the differences were not significant for the purposes of the application. It did not submit its interpretation of the pool, but said that it mapped the 6-8 and 8-17 wells into the same upper Colony pool. The intervener noted that since the two wells were in the same pool, it was reasonable to expect that there had been some drainage of the reserves associated with the 8-17 well; however, little evidence of current drainage had been presented.

Amoco agreed with the applicant that the lower Colony pool encountered by the 8-17 well is a single-well pool.

3.3 Views of the Board

The Board notes that there was no disagreement between the applicant and the intervener that the upper Colony sand pool encountered by the 8-17 well is part of the same upper Colony sand pool, the H Pool, that is being produced from the 6-8 well. The Board believes that the reserves associated with the 8-17 well are being drained by production from the 6-8 well. The Board considers it appropriate to revise the G Order defining the H Pool to include section 17-63-9 W4M, and, after a general review, to include any further changes to the boundaries of the pool.

The Board also notes that the applicant and intervener agreed that the lower Colony sand pool encountered by the 8-17 well appears to be a single-well pool.

4 NEED FOR A COMMON CARRIER ORDER

4.1 Views of the Applicant

Signalta estimated its share of the remaining recoverable reserves of the H Pool to be 17.5×10^6 m^3 on the basis that each of the four wells interpreted to be in the pool would share equally in the reserves. It calculated the recoverable reserves of the lower Colony pool encountered by the 8-17 well to be 15×10^6 m^3. The applicant said that it had a market for the gas producible from the 8-17 well with Pan-Alberta Gas Ltd. (Pan-Alberta). It was confident it could also arrange to sell additional volumes of gas from the well to other markets during periods of low nominations from Pan-Alberta to keep the well flowing competitively with the 6-8 well throughout the year. Signalta also noted that it had service on the NOVA Corporation of Alberta (NOVA) pipeline system downstream of the Ranger compressor station through its arrangement with Pan-Alberta.

Signalta considered it reasonable, efficient, and practical to expect the existing pipelines from the 6-8 well to the Ranger compressor station to deliver the currently identified reserves in the area. It estimated the life of the project associated with the 8-17 well to be a relatively short 8 years. It therefore proposed to build a pipeline from its 8-17 well to tie into the gathering facility at the 6-8 well, and to transport its gas on the existing system to the Ranger compressor station.

The applicant submitted that a reasonable arrangement would provide for tie-in of the gas from the 8-17 well at the 6-8 well, and competitive production of the 8-17 well with the 6-8 well throughout the year at a fee in the area of $\$4.01/10^3\ m^3$ of gas. Signalta also wanted the opportunity to make up the volume of gas it could have produced from the 8-17 well after 1 April 1991, the date at which it could have had its well tied in. The applicant evaluated the economics of the offers it received from Amoco and other alternatives available on a total project basis which included internal overhead, seismic, and land costs, with a goal of achieving a project-based, internal rate of return of 30 per cent, rather than on an incremental basis. It argued, however, that the economics of the offers and alternatives were not as critical as what is a practical solution to extracting the reserves in the area without a duplication of facilities.

Signalta considered the following four offers from Amoco and two other alternatives:

- the tie-in of gas from the 8-17 well at the 5-13 well, with access to the pipeline from that well to the compressor station on a reasonable-efforts basis for a fee of $\$4.18/10^3\ m^3$,
- the tie-in of gas from the 8-17 well at the 6-8 well, with access to the pipelines to the compressor station on a best-efforts basis, at a fee of some $\$9.81/10^3\ m^3$,
- the tie-in of gas from the 8-17 well at the 6-8 well, on an equalization basis wherein the applicant would purchase a share of the pipelines from the 6-8 well to the compressor station, resulting in firm service on a competitive basis throughout the year,
- the tie-in of gas from the 8-17 well at the 6-8 well under a firm service arrangement with a fee structure that incorporates a demand charge to be paid to Amoco regardless of whether or not the contracted-for capacity was used,
- the building of a new pipeline from the 8-17 well to the compressor station, and
- the tie-in of gas from the 8-17 well into a system proposed by Ranger in a project to expand the compressor station and build a gathering system to the north of the 8-17 well (see figure), on the basis of purchasing a share of the facilities involved.

Signalta argued that each of the offers or alternatives was unacceptable for one or more of the following reasons:

- provision for making up the volume of gas that Signalta could have produced from the 8-17 well after 1 April 1991 was not addressed or was rejected,
- the fees offered were too high,
- the economics, as evaluated on a project basis, did not meet the applicant's corporate financial goal and/or were less attractive than the economics of the proposed common carrier operation with the fee as proposed by the applicant,
- building a pipeline along a route involving a crossing of the Beaver River is undesirable from an environmental viewpoint,
- building duplicate pipelines is unnecessary and inefficient when existing pipelines can transport the reserves in the area in a reasonable period of time,

- the risk that the life of the 8-17 well would be short would not justify the applicant entering into any long-term arrangement,
- equalization is a logical means of obtaining capacity in a new facility; however, where the facilities already exist, it would be normal to contract to use the facility on a fee basis,
- equalization is capital-intensive and not justified by the risk that the 8-17 well will have a short life,
- a demand charge is not an industry standard in the type of situation associated with the 8-17 well, and
- a best-efforts arrangement would not assure gas from the 8-17 well competitive access to the pipeline throughout the year.

The applicant submitted that there are no existing pipelines, other than Amoco's, in close proximity to the 8-17 well that could be used to transport gas produced from the well.

Signalta considered its position and that of Amoco to be so far apart that it did not see a possibility that a satisfactory arrangement to use the existing pipelines could now be negotiated. It concluded it had no reasonable alternative but to request a common carrier order.

4.2 Views of Amoco

Amoco did not dispute that Signalta has reserves available for transportation or a market for the gas. However, the intervener doubted that the market would allow for consistent production throughout the year because Pan-Alberta generally offers low nominations during the summer months.

Amoco submitted that a common carrier order should be granted only in cases where there are no other economic alternatives that allow a party to alleviate drainage of reserves and where it is desirable to prevent unnecessary duplication of facilities. It argued that Signalta had a number of alternatives available, including offers from Amoco, that would realize a rate of return in excess of the 15 per cent previously considered by the Board to be reasonable*. The intervener further contended that the only reasonable way to evaluate the economics of the alternatives was on an incremental, not project, basis because present decisions are based on the expectation of future cash flow, not past costs.

The intervener noted that the pipeline from the 6-8 well to the 5-13 well has historically handled up to about 100×10^3 m^3/d. In the longer term, as the H Pool reserves now tied into the pipeline become depleted over the next 3 or 4 years and the pressure drops in the pipeline increase, the capacity of the pipeline would decrease to about 85×10^6 m^3/d. Amoco also observed that, while the pipeline from the 6-8 well to the 5-13 well is presently full, there is capacity available in the pipeline from the 5-13 well to the Ranger compressor station. Tying in the 8-17 well at the 5-13 well would be economic for Signalta and would allow both the 6-8 and 8-17 wells to produce at capacity. This would be an advantage if Ranger proceeds with plans to produce two new wells in Lsd 14-19-63-9 W4M and Lsd 3-25-63-10 W4M, which Ranger considers to be in the H Pool. Amoco acknowledged that the option of tying the 8-17 well in at the 5-13 well would not be the environmentally preferable option, but such a tie-in could be justified given that the pipeline from the 6-8 well to the 5-13 well is full.

---

* Energy Resources Conservation Board, 1985. Examiner Report E 85-19, Application 850324, Passburg Petroleums Ltd., Common Purchaser, Minnehik-Buck Lake Pekisko A Pool.

Notwithstanding its comments regarding the advantages of tying in Signalta's gas at the 5-13 well, Amoco said that it was prepared to share the capacity of the pipeline from the 6-8 to the 5-13 well. Its offers to Signalta to allow access to the pipeline for gas from the 8-17 well on the basis of equalization or on a best-efforts basis (as described briefly in Section 4.1 of the report) would be economic for the applicant. Amoco would also be prepared to offer firm service on the basis of a fee and a demand charge, but it did not present an economic analysis of this option. It contended, however, that the demand charge concept was normal within the industry. The intervener further argued that the specific fees offered to Signalta were reasonable ones calculated using the Jumping Pound 90 formula, which allows for a range of fees applicable in different circumstances. Amoco said that in any event, the fees offered would be open to negotiations. Finally, the intervener was not prepared to include an opportunity for Signalta to make up for past drainage of reserves from the applicant's property as part of an agreement allowing Signalta access to Amoco's pipelines. Amoco contended that if Signalta had accepted one of the offers made, it could produce its entire share of the reserves of the H Pool in about 3 years.

With respect to other alternatives, Amoco calculated that tying the 8-17 well into the proposed Ranger system would also be an economic option for Signalta. It also noted that it had never suggested that building a new pipeline from the 8-17 well to the compressor station was an alternative to be considered.

Amoco contended that Signalta had not conducted adequate negotiations to resolve the issues involved, and, further, had not availed itself of reasonable, economic options to tie in and produce the 8-17 well. It argued that Signalta was attempting to improve the economics of the 8-17 well by means of a common carrier order. However, it was the intervener's view that it is not the Board's role to find the best deal for Signalta, and therefore, the application for a common carrier order should be denied.

4.3 Views of the Board

The Board has indicated in previous reports that a successful applicant for a common carrier order would be required to satisfactorily demonstrate that

- producible reserves are available for transportation through an existing pipeline,
- there is a reasonable expectation of a market for the substance which is proposed to be transported by the common carrier operation,
- the applicant could not make reasonable arrangements to use the existing pipeline, and

- the proposed common carrier operation is either the only economically feasible way or clearly the most practical way to transport the substance in question, or is clearly superior environmentally.

The Board accepts the evidence and statements that there are reserves producible from the 8-17 well for transportation through the existing pipeline, and that the applicant has a Pan-Alberta market and NOVA transportation available for the gas. The Board also accepts that there is a reasonable expectation, given the current gas marketing environment in the province, that gas from the 8-17 well could be delivered to other markets during periods of low nominations from Pan-Alberta.

The Board notes that the life of the two pools of interest is likely to be relatively short, probably less than 8 years. Further, it appears to the Board that the pipeline from the 6-8 well to the Ranger compressor station could deliver the reserves from the pools in a reasonable period of time with minimal additional pipeline construction. The existing pipeline therefore represents a practical and efficient means of transporting gas from the 8-17 well.

Having regard for the desirability of avoiding unnecessary duplication of facilities, the Board considers the options of tying gas from the 8-17 well into the existing gathering system at the 5-13 well, or building a new pipeline from the 8-17 well to the compressor station, to be less satisfactory alternatives. In addition, the Board considers the option of tying gas from the 8-17 well into the proposed Ranger pipeline to be impractical, in that drainage would continue to occur from Signalta's reserves while the system was being built, and the tie-in poses a greater environmental impact. The Board agrees with Signalta that it would be imprudent to accept access to the Amoco pipeline from the 6-8 well on a best-efforts basis because this would not adequately protect Signalta's reserves from drainage by other wells producing from the H Pool in the future. It was not apparent from the evidence that Signalta was prepared to negotiate with Amoco on that basis.

The Board is not persuaded by the evidence and argument presented that the other options to tie in the 8-17 well at the 6-8 well on the basis of firm service for a fee for throughput and a demand charge, or on the basis of equalization, would not represent opportunities that could have reasonable and economic terms and conditions, particularly in view of Amoco's statements that it is still prepared to negotiate. The Board is of the opinion that an operator whose reserves are being drained should avail itself of any reasonable opportunity to put its gas on production and alleviate the drainage. Any agreement which would be economic by current standards, and which includes terms and conditions that were normal in industry, would be a reasonable contract. Such conditions would recognize the proper return on risk capital provided by the owner of the pipeline that could be declared a common carrier. Accordingly, the Board is of the view that it would be inappropriate for Signalta to reject Amoco's offers out of hand, if these were economic and had reasonable terms and conditions. The Board believes the common carrier provisions should not be used to guarantee optimum economic return to an applicant.

The Board is also not entirely satisfied that negotiations to obtain an agreement to allow Signalta access to the pipeline from the 6-8 well were consistently pursued in a timely manner with both parties contributing in a give-and-take process incorporating suggestions as to how matters could be resolved. It notes that the reluctance by Amoco to discuss or offer firm service on a fee basis until the advanced stage of negotiations could be taken by Signalta as an unwillingness to negotiate equitable terms. The Board acknowledges that discussions that took place appeared to be at an impasse at the time of the hearing because of Signalta's perception that the two parties were far apart on the terms and conditions of a possible agreement.

Although Signalta may have failed to avail itself of a reasonable opportunity to place its gas on production, the Board is nevertheless not prepared to reject the common carrier application solely on this basis. The Board agrees with Signalta that the Amoco pipeline from the 6-8 well appears to be the most practical technical option to tie in production from the 8-17 well. The proximity of the pipeline to the 8-17 well would minimize environmental impacts and should be cost-effective. Further, given the evidence that the life of the H Pool is likely to be relatively short, the Board does not believe it is in the public interest to compel the construction of another pipeline for this production, when the Amoco pipeline would likely be underutilized within a short period of time. In view of the above, and having regard for the impasse between the two parties, the Board is prepared to grant the common carrier application.

The Board believes that normal commercial arrangements are best resolved through fair and honest negotiations between the parties. Such issues should only be resolved by regulatory order as a last resort. The Board notes that because it is prepared to issue a common carrier order and has identified the terms of that order (in Section 5.3), the parties' positions may have changed, and further discussions between them may lead to an agreement. Accordingly, the Board will defer requesting approval from the Lieutenant Governor in Council for the issuance of the common carrier order for a period of 2 calendar months following the date of this report, so that Signalta and Amoco may pursue further negotiations to establish common ground and perhaps eliminate the need for a common carrier order.

5 DETAILS OF THE COMMON CARRIER ORDER

5.1 Views of the Applicant

Signalta noted that historically, common carrier orders were applied in situations where drainage had been an issue. However, it requested that both the H Pool, where drainage is an issue, and the lower Colony pool, where drainage is not a factor, be subject to the common carrier order. It argued that if the lower Colony pool were not made subject to the common carrier order because no drainage is occurring, gas from the pool could be excluded from the pipeline for a considerable period of time or be transported only on payment of tariffs that may not be within normal industry ranges.

Notwithstanding its request that the two pools of interest be named in the common carrier order, the applicant noted that the Act did not require the naming of pools subject to a common carrier order, and it would not object if the Board chose not to specify the pools in this case. Signalta considered that, in cases as exist in the area of interest, where a pipeline would be capable of transporting the reserves in the area over a reasonable period of time, it may be appropriate not to specify the pools that would be subject to a common carrier order.

Signalta requested that the common carrier order be made effective on 1 April 1991, about 1 week after it filed its application. This effective date would address the prejudicial effect of continued drainage of Signalta's share of reserves in the H Pool occurring between the time the application was filed and its final disposition. The applicant also suggested that the retroactive effective date of the common carrier order could serve as a penalty in situations where there is no drainage issue but where a party created a great deal of inequity by not allowing access to facilities on reasonable terms. The applicant proposed that the retroactivity portion of production under the common carrier order be implemented by shutting in the 6-8 well and flowing the H Pool from the 8-17 well to produce the same volume as had been produced from the 6-8 well from 1 April 1991 until the well had been shut in. It anticipated that it could take from 1 to 1.5 years to produce the retroactive volumes. Signalta proposed that, once these volumes had been produced, the common carrier order would be implemented by allowing the 6-8 and 8-17 wells to compete in an unencumbered manner. It expressed a preference to produce the H Pool first, and as the rate from the pool declined, it would then produce the lower Colony pool to maintain its sales nominations.

Signalta argued that it had taken all the steps under its control to tie in its well and commence production on 1 April 1991. The process the applicant followed to evaluate the potential of section 17-63-9 W4M and to drill the 8-17 well was similar to that followed for virtually every development in which it has been involved. The applicant has a Pan-Alberta market for its gas effective 1 April 1991, with associated capacity on the NOVA pipeline system downstream of the Ranger compressor station (as previously described in Section 4.1 of the report). Signalta had an indication in January 1991 that there was best-efforts capacity at the Ranger compressor facility. The applicant had determined the route for a pipeline tying in gas from the 8-17 well into the existing gathering system at the 6-8 well, paid out the required pipeline easements, awarded pipeline construction contracts, and applied for a pipeline permit. However, because the question of where its gas should be tied into the Amoco pipeline remained unresolved, the permit has not been issued. The applicant argued that if it had been able to settle the question of the tie-in point and receive its permit in a timely manner, it would have been able to construct its pipeline in about 1 week and commence production from the 8-17 well on 1 April 1991.

The applicant acknowledged that in December 1991, circumstances changed with respect to the capacity at the Ranger compressor facility. Signalta interpreted a letter dated 2 December 1991 from Ranger on this matter to mean that if all wells now tied into the compressor facility produced at the contracted maximum daily volumes, the facility would be full. However, the applicant doubted that the maximum daily volume would be nominated on a consistent basis by the purchaser, and it speculated that there could still be some capacity available. Signalta intended to meet with Ranger and determine what capacity would be available. If the service was inadequate, it proposed to install additional equipment adjacent to the Ranger site which would provide compression for its share of gas but make use of the existing Ranger dehydration equipment. The applicant had not yet reviewed the technical aspects of tying additional equipment into the Ranger facility, but anticipated that it would take about 4 months to install the equipment. It stated that, in any event, it would take the responsibility to make the necessary arrangements respecting the compression it would require for its gas.

Signalta noted that numerous telephone contacts, letters, and meetings between Amoco and the applicant starting on 29 January 1991 and continuing through 19 July 1991 had failed to result in any mutually satisfactory arrangements to allow gas from the 8-17 well to be transported through the existing Amoco gathering system. The applicant did not meet with Amoco prior to filing the application, nor respond formally to all the offers made, nor make any counter-offers because of a perception that its position and Amoco's were so far apart that the matter was not worth pursuing. It was the applicant's opinion that there was now no chance of negotiating a settlement. Signalta concluded that it had done everything reasonably possible to resolve matters with Amoco, and there was no reason not to make the common carrier order effective on 1 April 1991 as requested.

Finally, the applicant confirmed that it did not expect the common carrier order to address the tariff it would pay to transport its gas on Amoco's pipeline, or the allocation of production between the 6-8 and 8-17 wells after the retroactivity aspect of the order had been met.

5.2 Views of Amoco

Amoco submitted that if the Board issued a common carrier order, it should stipulate that it applies to the H Pool, because this pool is the only one where drainage is an issue. Conversely, there would be no justification for making the lower Colony pool producible from the 8-17 well subject to the order, because the pool is a single-well pool and there is no risk of another party draining Signalta's gas from the pool. The intervener said that if the pipeline between the 6-8 and 8-17 wells were in place because of the common carrier order applying to the H Pool, the pipeline would be available for lower Colony gas when the H Pool became depleted. Amoco argued that, even if the lower Colony pool reserves were shut in for a long period of time, it would not be a circumstance in which the Board ought to intervene.

Amoco opposed the request to make the common carrier order effective on 1 April 1991. The intervener argued that the retroactive aspect of the effective date was not required because Signalta would have the opportunity to drain its share of the H Pool reserves without such provision. As noted in Section 4.2 of this report, Amoco estimated that Signalta could recover its share of the reserves in about 3 years if it accepted one of the offers made by Amoco.

The intervener also argued that the retroactive effective date would not be justified because Signalta has not been diligent in its efforts to resolve the issues related to drilling and preparing its well for production. Amoco contended that Signalta had not thoroughly investigated the availability and economics of capacity in the existing pipelines before drilling the 8-17 well, had filed the common carrier application before attempting to negotiate a normal commercial settlement, had not formally responded to all of Amoco's offers, and did not suggest alternative means of resolving the issues involved. The intervener said that it had made most of the efforts to settle the matter, even though the onus should have been on Signalta, the party claiming drainage of its gas. Amoco said that it was still prepared to negotiate on the previous offers it made.

The intervener also contended that the requested effective date should be rejected because Signalta has not demonstrated that it could have produced the retroactive volumes of gas starting on 1 April 1991. Amoco questioned whether the Pan-Alberta market could have taken the gas volumes involved. The intervener also argued that Signalta had not presented any evidence that there was capacity at the Ranger compressor facility arranged for after 1 April 1991, had not completed any technical work with Ranger regarding the possibility of tying in additional equipment, and had not communicated with the Board about the feasibility of placing a new installation adjacent to the Ranger site.

Finally, Amoco submitted that the Board should consider the consequences of a retroactive effective date. It said that if the effective date requested by Signalta is granted and implemented as proposed, Amoco would be required to shut in the 6-8 well. In this circumstance, the H Pool production from the 8-17 well and possible production from the two new Ranger wells would drain substantially all of the reserves that could be economically produced from the 6-8 well, reducing the value of the 6-8 well to nearly zero.

Amoco concluded that it opposed the granting of the common carrier order, but if the Board were convinced that the order is needed, there was no justification for making it effective in a retroactive manner.

5.3 Views of the Board

The Board considers the issuance of a common carrier order to be a very significant action because the order has the potential to override contractual arrangements put in place through normal business practices. For this reason, the Board believes it appropriate to limit the impact of the order as much as is practical.

The Board acknowledges that, in some situations, it could be appropriate not to specify the pools subject to a common carrier order, as suggested by Signalta. However, in the present case, the Board is of the view that there was insufficient evidence presented to allow a proper evaluation of the need and impact of a common carrier order applying to any pool in the area. Indeed, no notice was provided that such a potentially broader issue could be reviewed. Accordingly, the Board believes that it would be appropriate to specify the pools to which the common carrier order would apply in this case.

The Board is of the view that the H Pool, where drainage of Signalta's reserves is an issue, should be named in the order. However, it is not convinced that it would be appropriate to also include the undefined lower Colony pool of interest in the order. In view of the likelihood that the deliverabilities of wells in the H Pool will decline in the next few years, and the probability that the life of the H Pool will be relatively short, it appears that there could be capacity in the pipeline for the lower Colony reserves from the 8-17 well within a reasonable period of time.

The Board notes that, although Ranger has an interest in the H Pool, it has chosen not to participate in this hearing. The Board also notes the evidence that Ranger is planning its own gathering system. There appears to be potential for other development in the area which has not been fully discussed at this hearing. Therefore, the Board considers it appropriate to further limit the impact of the common carrier order by specifying that only the 6-8 and 8-17 wells would be subject to the order.

In determining the effective date of the common carrier order, the Board considered the detrimental effects to the applicant caused by the delay between the time the application was made and its disposition, the conduct of the applicant in preparing its well for production, and the impact of the effective date on the parties involved.

By 7 April 1991, almost 3 years of production from the H Pool through the 6-8 well had resulted in a decline of some 30 per cent in the pool pressure from the expected initial values at the 8-17 well. Having regard for the decline in pool pressure during this period, the Board considers it highly probable that there has been a further significant decline in the pressure of the H Pool at the 8-17 well during the almost 1 year that has elapsed since the application was submitted. The Board notes that

Amoco considered it reasonable that drainage of Signalta's gas is occurring and concludes that the time taken to process the application has had some impact on Signalta in that an additional volume of its reserves has been drained during the period.

The Board observes that Signalta prepared to tie in the 8-17 well by obtaining a market for the gas and by completing the plans for the pipeline between the 6-8 and 8-17 wells to the extent possible, given the status of its discussions with Amoco. However, the Board is concerned that the applicant apparently did not finalize an agreement for capacity at the Ranger compressor station early in the process, and when the circumstances later changed regarding the compressor station, it did not immediately make serious efforts to discuss and resolve the matter with Ranger. In addition, as previously noted in Section 4.3 of the report, the Board is concerned that Signalta did not enter fully into negotiations with Amoco to tie gas from the 8-17 well into the existing gathering system at the 6-8 well. In the Board's opinion, normal negotiations involving the issues in this case should include a substantial degree of discussion of offers and counter-offers prior to the submission of a common carrier application, and should have continued during the processing of the application. On the other hand, it appears to the Board that Amoco's actions in response to contacts made by Signalta were not as timely as the Board would have expected.

Given the circumstances of this case, the Board believes a reasonable period to conclude negotiations and secure the necessary capacity in the compression facility would be between 3 and 9 months. In view of the foregoing, the Board believes that the effective date of the common carrier order should be 1 September 1991.

The Board would expect the common carrier order to be implemented by prompt and cooperative action by both Signalta and Amoco to get the 8-17 well tied in and producing. As of the effective date of the order, production from the 6-8 and 8-17 wells should be balanced to allow each party the opportunity to produce a fair and reasonable share of the reserves of the H Pool. However, the Board believes it would be inappropriate to order the 6-8 well to be shut in while any retroactive volumes are produced from the 8-17 well. The parties are free to negotiate how any retroactive volumes are to be produced. However, the Board would suggest that there should be some agreement as to what proportion of production should be allocated to each well, and that the production should be equalized within a 2-year period.

The Board acknowledges that Signalta has not asked for a specific allocation of production under the common carrier order, except in respect of implementing the retroactive aspect of the order. The Board would, however, be prepared to deal with the matter of allocation to give effect to the common carrier order. If so requested and justified by an interested party, the Board would provide a recommendation of what it believes to be a fair and equitable distribution of production under the common carrier order. As an alternative, a party may obtain a more formal allocation of production by submitting a successful application under section 23 of the Act for a rateable take order.

6 DECISION

For the reasons noted above, unless the application is withdrawn by Signalta Resources Limited within 2 calendar months of the date of this report, the Board will approve the common carrier application. Approval of the application will be subject to the authorization of the Lieutenant Governor in Council and will declare Amoco Canada Petroleum Company Ltd. as a common carrier of gas produced from the Sugden Grand Rapids H Pool, through two existing wells located in legal subdivision 6 of section 8 and in legal subdivision 8 of section 17, both of township 63, range 9, west of the 4th meridian. The Board denies the application as it pertains to the undefined Colony pool referenced in the application. The common carrier order would apply to only those pipelines extending from a well located in legal subdivision 6 of section 8, township 63, range 9, west of the 4th meridian, to a compressor station located in legal subdivision 11 of section 7, township 63, range 8, west of the 4th meridian. The common carrier order would be effective as of 1 September 1991.

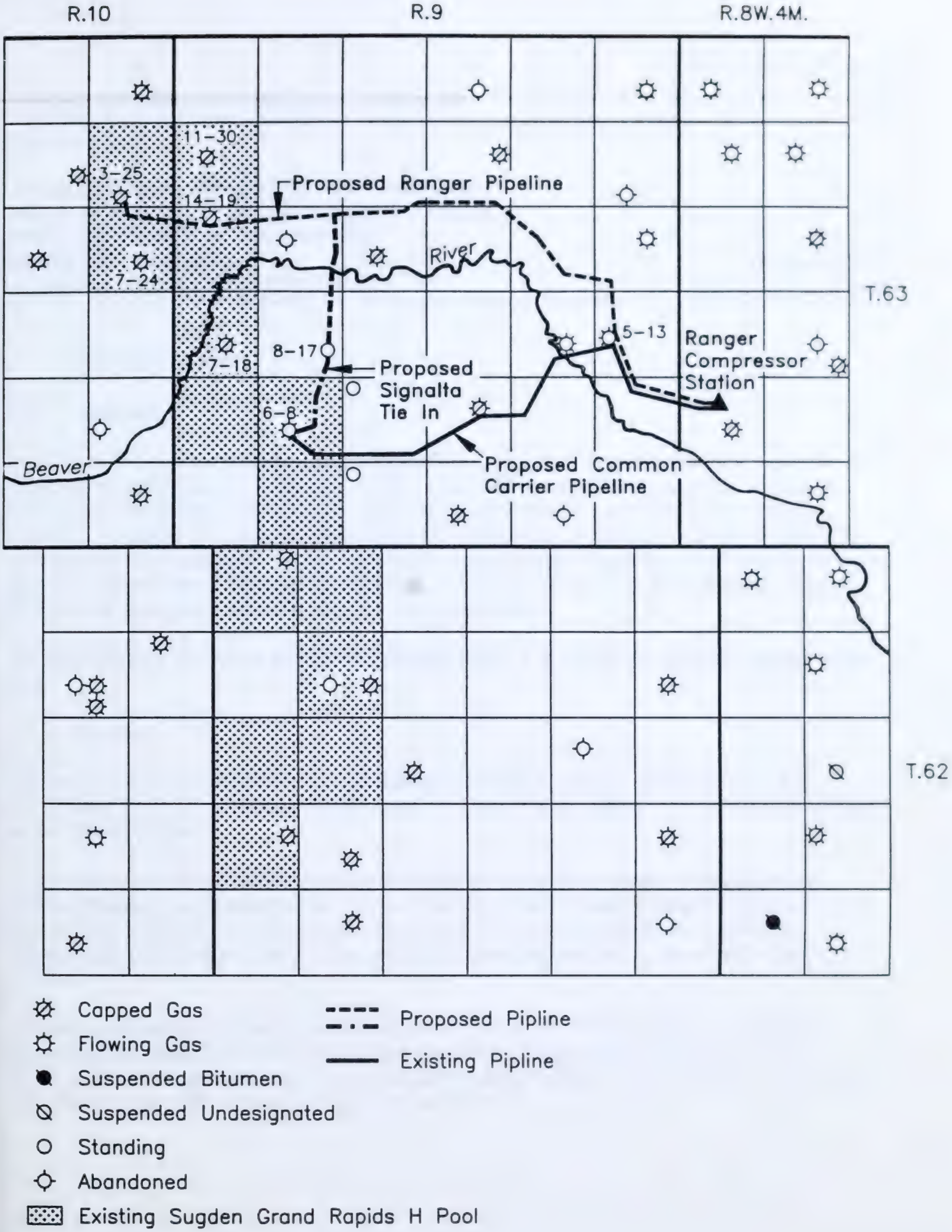
Dated at Calgary, Alberta, on 16 April 1992.

Energy Resources Conservation Board

F. J. Mink, P.Eng.
Vice Chairman

N. G. Berndtsson, P.Eng.
Board Member

K. G. Sharp, P.Eng.
Acting Board Member



SUGDEN AREA OVERVIEW
Application No. 910454

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION BY FEDERATED PIPE LINES LTD.
FOR A PERMIT TO CONSTRUCT A HIGH VAPOUR
PRESSURE PRODUCTS PIPELINE AND
METERING FACILITIES
ACHESON TO FORT SASKATCHEWAN

Decision D 92-3
Application No. 920128

1 INTRODUCTION

1.1 Application

Pursuant to Part 4 of the Pipeline Act, Federated Pipe Lines Ltd. (Federated) applied for approval to construct approximately 64.4 kilometres of 273.1-millimetre outside diameter high vapour pressure (HVP) products pipeline from an existing metering station located in Legal Subdivision (Lsd) 5, Section 2, Township 53, Range 26, West of the 4th Meridian near Acheson, to a proposed metering station near Fort Saskatchewan, and to construct the proposed metering station at Lsd 8-14-55-22 W4M near Fort Saskatchewan. Federated also applied for approval to install four short segments of spare pipeline near Fort Saskatchewan to allow for future connections.

The proposed pipeline route is shown in the attached Figure 1 along with certain major features of the area.

1.2 Hearing

The application was considered at a public hearing in Edmonton, Alberta, on 5 May 1992, with J. P. Prince, Ph.D., R. G. Evans, P.Eng., and J. D. Dilay, P.Eng., sitting. The participants are listed on the following table.

At the hearing, the Board staff suggested to the Board that it encourage further communications between Federated and landowners Mr. Puszkar and Mr. Tworek outside the hearing process to try to resolve some of the concerns raised by the landowners. The parties accepted this suggestion. Subsequently, the Board was advised that negotiations have continued but no agreement has been reached.

Following the hearing, the Board made arrangements to view Mr. Puszkar's and Mr. Tworek's properties (Southeast 17-53-26 W4M) and other parts of the pipeline right of way (R.O.W.) on 27 May 1992. The applicant and all registered interveners participated. Details of Mr. Puszkar's and Mr. Tworek's properties are shown in the attached Figure 2.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Federated Pipe Lines Ltd. (Federated) A. S. Hollingworth C. I. MacLean	M. J. Massecar, P.Eng. R. W. McKay, P.Eng. B. H. Blattler, P.Eng. D. A. Schnell of Emplan Emergency Planners Ltd. M. J. Zelensky, P.Eng. of Concord Environmental Corporation
Joe's Auto Electric Ltd. J. Puszkar	J. Puszkar
P. A. Tworek	P. A. Tworek
P. A. Young	P. A. Young
T. Morrison	T. Morrison
Alberta Environment W. MacDonald H. Slavinski G. Murphy	
Energy Resources Conservation Board staff M. Bruni S. Lee, P.Eng. J. Amoruso D. Pane I. Dowsett	

2 ISSUES

The Board believes that the issues relevant to the application are:

- the need for the pipeline,
- routing,
- public safety,
- additional concerns of landowners, and
- other matters.

3 NEED FOR THE PIPELINE

3.1 Views of the Interveners

The interveners did not express any views about the need for the proposed pipeline.

3.2 Views of the Applicant

Federated stated that it has entered into an agreement with Shell Canada Limited (Shell) to transport Shell's natural gas liquids (NGLs)[1] from Caroline to storage and processing facilities near Fort Saskatchewan. It stated that the proposed pipeline is needed because the existing pipeline system does not have the capacity or operational flexibility required to transport the additional volumes. To accommodate Shell's schedule, it preferred to start construction in July 1992 and to complete construction by 1 December 1992. Federated indicated that, should there be a delay in approval, it would reschedule construction so that the river crossings and upland areas would be completed in September and October 1992 with construction in wet areas to proceed as soon as frost conditions permit. It further indicated that, if frost conditions do not permit construction in time, it would temporarily transport the NGLs through these wet areas using the existing line and construct a cross-over into the completed portions of the proposed line. Federated also stated that any unusual delay would present substantial difficulties for Federated and could create constraints on the start-up of Shell's Caroline plant.

3.3 Views of the Board

The Board notes that the interveners expressed no concern about the need for the proposed pipeline. It accepts that the existing pipeline does not have sufficient capacity and therefore, that there is a need for the additional line.

4 ROUTING

4.1 Views of the Interveners

Both Mr. Puszkar and Mr. Tworek said that, when they purchased their land, they were not aware that there was already an HVP pipeline located on their properties. They argued that, although they signed the routing agreement with Federated, they did not realize that it was intended to confirm their consent for the proposed line and added that they do not really want additional HVP lines on their land. They further indicated that, if the pipeline does need to traverse their land, they would prefer to have it located parallel to the property line or to have Federated buy their land.

---

[1] NGLs are classified as HVP products.

4.2 Views of the Applicant

Federated said that the landowners signed a routing agreement which, in its opinion, gives Federated routing approval as well as permission to perform the legal survey and soil survey of their land. Federated indicated that the proposed pipeline route would follow an existing HVP pipeline, thus minimizing the impact upon the landowners and any possible future developments on other portions of their properties. Federated said that routing the pipeline along the property line would further impact the land and would create a new area that would have to be dealt with in its operation and emergency response planning.

While not relevant to the disputed area, Federated stated that it also evaluated an alternative route which would utilize a portion of the Restricted Development Area/Edmonton Transportation and Utility corridor, but rejected it for reasons related to public safety and future development plans in the area.

4.3 Views of the Board

The Board notes that, although Mr. Puszkar and Mr. Tworek signed a routing agreement with Federated, they have clearly stated that they do not want an additional pipeline on their land.

The Board believes that the proposed routing along the existing lines is superior to an alternative route along the north property line of the Puszkar and Tworek parcels because it would not further fracture the parcels. In addition, it would be more direct and slightly shorter, and would not require an increased emergency planning zone. The Board agrees with Federated that paralleling the existing line implies the least potential impact on the land.

5.0 PUBLIC SAFETY

5.1 Risk Considerations

5.1.1 Views of the Interveners

Mr. Puszkar and Mr. Tworek were concerned about the safety of themselves, their families and others. Mr. Puszkar owns a trailer located on his parcel approximately 300 metres from the pipeline R.O.W.. This trailer is presently rented to others. Mr. Tworek and his family live approximately 70 metres from the pipeline R.O.W.. Both said that, prior to a public information meeting held by Federated about the proposed line in St. Albert in the fall of 1991, they were unaware of what the existing pipeline carried and the degree of hazard associated with it. Mr. Tworek stated that, prior to the meeting, he had not received a pipeline information package from Federated. He also expressed concern that the existing pipeline may be damaged during the construction of the new pipeline.

Mr. Morrison lives approximately 13 km from the proposed pipeline. Although he did not present evidence, he asserted that the impacts predicted from the use of dense gas dispersion models are not comparable with the impacts demonstrated by historic events. Mr. Morrison said that the differences between the real and predicted impacts are significant and that these differences need to be better understood and explained. He also claimed that the operational philosophy and practices of Federated and the ERCB are focused on economic rather than safety considerations. Mr. Morrison indicated that significant catastrophic impacts have resulted from failures at similar facilities elsewhere in the world. He questioned whether the details of historic events had been thoroughly researched and understood. He asked if there was a means for reviewing the historical evidence.

He questioned whether wind and terrain were used in the modelling of Federated's assessment. Mr. Morrison stated that, although dispersion models do not properly reflect real situations, they could be used to aid on-site responders during a real emergency. In his view, an effort should be made to use dispersion models as dynamic tools rather than in a historical context.

Mr. Morrison also argued that dense gas releases from small leaks could continue undetected, may accumulate and could constitute a danger.

Mr. Morrison expressed concern about the best course to be followed by people affected by a release. He questioned whether residents should be or could be evacuated, or if they should take shelter.

5.1.2 Views of the Applicant

Federated responded that levels of risk associated with the operation of the proposed pipeline are within the range of acceptable risk suggested by other agencies. Federated has, wherever possible, adopted voluntary separation distances of 200 metres between its pipeline and individual residences and 1000 metres from heavily populated areas. The estimated levels of risk presented by Federated for the proposed facility represent the maximum values which would result from a full pipeline rupture lasting approximately 15 minutes. According to Federated, for residents near both the existing and proposed pipelines, the levels of risk would be doubled. In Federated's view, all levels of risk, including those which are associated with the existing pipeline, are within acceptable limits.

Federated stated that a full pipeline rupture represents the worst-case situation. The use of the worst-case estimates provide a meaningful indication of the maximum extent of a cloud which could be expected under a wide range of conditions. Other scenarios (ie. different weather conditions, smaller leak rates) would pose less risk. It would be difficult to anticipate the extent of a release in high-slope terrain where gravity may be a factor. However, the use of estimates based on a full pipeline rupture provide a reasonable starting point for responding to an emergency.

Federated estimated the annual levels of risk of fatal injury to an individual living at the voluntary setback distance of 200 metres to be 0.5 chances in a million. It estimated the level of risk at 100 metres (Federated's initial estimated distance to Mr. Tworek's home) to be 4 chances in a million. (The distance was later measured to be about 70 metres.) While this level of risk is higher than that at the voluntary setback distance, Federated indicated this risk to be within generally accepted limits. Federated stated that the proposed pipeline has been designed to CSA Z-183-M90, Zone 2 criteria, which exceed the Zone 1 criteria required for pipeline construction in this area. Federated also noted that it had not had a failure on the existing pipeline. It believed the careful design and operation of its facility would make it safe to live at this distance.

Federated stated that the dispersion model used would accurately predict the dispersion from HVP releases, based on comparisons with controlled field experiments. Federated, through Concord Environmental Corporation, actively solicits, obtains and reviews reports on major accidents on an ongoing basis. These reviews include material from newspapers and journals. More emphasis is placed on journal information as it tends to be more factual. On the basis of its reviews, Federated believed the dispersion and risk predictions to be reasonable.

5.1.3 Views of the Board

Notwithstanding the assertion of the landowners that they were unaware of the nature of the product being transported through the existing HVP pipeline crossing their land, the Board notes that, in addition to the pipeline easement on the land title and the information about the nature of the product as stated on the road-crossing signs nearby, further information could have been readily obtained from the ERCB or the operator upon request.

It is the Board's view that both economic and public safety matters must be addressed when considering applications for facilities. In this case, while recognizing that there would be incremental risk associated with the proposed pipeline, the Board believes that this increment would not be significant and would fall within acceptable limits.

The Board acknowledges Mr. Tworek's concern regarding safety during the construction of the pipeline. The Board believes that mitigative measures could be taken, particularly during construction, to minimize the possibility of damage to the existing pipeline. If the pipeline were approved, ERCB staff would review Federated's construction surveillance practices and would increase inspections in the area of the Tworeks' dwelling.

The Board agrees with both Federated and Mr. Morrison that where verifiable evidence from past failures is available, it should be considered in assessing potential future risks.

The Board has strictly enforced regulations pertaining to the design and operation of pipelines with the objective of ensuring that pipeline systems will not fail and that any public hazard would be minimized. The Board believes that the risk associated with small, undetectable leaks does not pose any significant danger to the public.

The Board places heavy emphasis on ensuring that the operator shows appropriate consideration for public safety and acknowledges Federated's initiative in addressing safety. In addition, given the proximity of the Tworeks' residence and the gravel pit operation, the Board would require that Federated erect warning signs at intervals, to clearly and continuously mark the location of the pipeline, in a similar fashion to current ERCB requirements for urban areas. The Board would further require that Federated notify the Tworeks' in advance of each phase of construction in the vicinity of their dwelling.

5.2 Mitigation

5.2.1 Views of the Interveners

Mr. Morrison expressed concern about the material balance sensitivity of Federated's leak detection system. He argued that the proposed capability for detecting leaks in excess of 2 per cent of the volume is not adequate. He was also concerned that leaks that occur underground might not be detected in time to initiate any response activity. He believed that the leak detection sensitivity of the

Sieger "searchline" technique would be higher and that it should be compared with the mass balance approach that Federated is taking. Mr. Morrison did not explain the technique nor why its sensitivity would be higher. Mr. Morrison was also concerned about the shut-down procedure utilizing the Supervisory Control and Data Acquisition (SCADA) System.

Ms. Young, who lives approximately 13 km from the proposed pipeline, was concerned that the capability of Federated's SCADA System was inadequate for winter detection and night detection.

Both of the interveners suggested that the Board and industry should continue to promote and look for better leak detection methods.

5.2.2 Views of the Applicant

In response to the concerns raised by Mr. Morrison and Ms. Young respecting leak detection capabilities, Federated stated that the proposed pipeline, which is to be installed in Zone 1 areas, would be designed and operated to meet or exceed Zone 2 requirements for leak prevention and detection. Federated claimed that its SCADA System, though designed for detecting leaks in excess of 2 per cent of the volume, is capable of detecting leaks as small as 1 per cent in 6 hours. Federated said that leaks smaller than 1 per cent would require other means of detection such as visual observation and reporting of leaks by landowners so that Federated could respond accordingly. Federated also indicated that its SCADA System is not specific to any particular season or time and that it would be able to detect leaks at anytime.

Federated also argued that vapour released from underground leaks would make its way to surface and would be visually detected.

With respect to Mr. Morrison's concern about the shutdown procedure using the SCADA system, Federated responded that its leak detection method involves a two-step process. The SCADA system would first signal a warning that there is a change in the operation of the pipeline system. A leak alarm, as a second step, is activated when a dynamic model indicates that a release of product may have occurred. Federated stated that, although it receives daily warnings, it does not receive leak alarms on a day-to-day basis.

Federated did not believe that leaks below 2 per cent would present any immediate hazard to the public and therefore did not support participation in a review of more sensitive approaches to leak detection.

5.2.3 Views of the Board

The Board notes Mr. Morrison's concern with regard to leak detection for small leaks. However, the Board considers the proposed leak detection capability to be satisfactory, and to provide an acceptable level of safety.

The Board recognizes the SCADA system to be an effective tool for leak detection and believes that the actual shutdown procedure to be used should depend on the type of indication by SCADA. The Board believes that the operator and the SCADA system together form integral parts of an effective leak detection method. Therefore, the Board is satisfied that the two-step leak detection method involving input from the operator, as proposed by Federated, is appropriate.

The Board also accepts that the SCADA system is not specific to any particular season or time and that it would be able to detect leaks at anytime.

5.3 Emergency Response

5.3.1 Views of the Interveners

Mr. Morrison and Ms. Young were generally concerned about emergency response planning, communication and planning zones. Mr. Morrison suggested that emergency planners should submit a "justification report" containing industrial engineering calculations to establish the feasibility of responses outlined in an emergency response plan. This document would address logistical problems of quantities and time constraints of people and materials. He expressed concern regarding Federated's approach to prioritizing resident calls during an emergency and the difficulties in keeping resident information current.

Mr. Morrison suggested that the ERCB should propose and encourage the industry to establish emergency response co-operatives. He noted that smaller companies such as Federated may not have sufficient manpower to effectively respond and suggested the assistance from other industrial operators to fulfil manpower requirements.

Mr. Morrison and Ms. Young were both concerned about the potential for failure of telephone communication during an emergency. Mr. Morrison suggested a co-operative arrangement using long-life battery radio systems to communicate with residents in emergency evacuation zones. Ms. Young proposed the use of radio and television media to warn the public and emphasized that there should be a back-up system to the telephone.

With respect to emergency planning zones, Mr. Morrison suggested that the ERCB should establish emergency evacuation zones consistent with the Canadian Transport Emergency Centre (CANUTEC) Guideline (1500 metre radius) or with the reported damage area from the 1989 incident in the former Soviet Union (reported in news media as 1 km plume dispersion prior to explosion and 4 km radius of shock wave impact).

Ms. Young stated a preference for a two-level emergency response plan to be in place for more densely populated areas although she acknowledged that there are certain portions of the pipeline where a three-level emergency response plan would be appropriate. She also noted that another operator in the same area has a two-level plan and suggested that, in the interest of public safety, Federated should adopt a two-level approach to avoid confusion.

Both Ms. Young and Mr. Morrison commented that there is not enough training for HVP pipeline operators but did not elaborate on the basis for the concern. Ms. Young was concerned that the industry training for HVP emergencies does not adequately emphasize the difference between training situations and possible real emergencies, as not all emergency situations can be simulated in training. Mr. Morrison urged the ERCB to present a proposal to the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA) to develop additional accreditation requirements for professionals working in the HVP pipeline industry.

5.3.2 Views of the Applicant

Federated stated that it is currently updating its resident information, and is exploring methods to enhance its response mechanism through improved resident information update systems and mapping.

Federated stated that the owner of the pipeline is the most knowledgeable to respond to an emergency. Federated noted that a co-operative effort is in effect by industry for the more densely-populated areas through which its pipeline traverses.

In response to Mr. Morrison's comments on the CANUTEC Guideline for evacuation, Federated said that the CANUTEC recommendation only applies to rail and road transportation systems where the concern is that an explosion will cause the vessels to break apart and "rocket". It argued that pipelines, being buried facilities, will not behave in the same way.

Federated stated that the 800-metre planning zone adopted in its plan is conservative and represents a reasonable distance for emergency response. Federated noted that the three-level response mechanism adopted in its plan is in accordance with guidelines for response to HVP emergencies currently being developed by the industry through the Canadian Petroleum Association.

With respect to Mr. Morrison's and Ms. Young's comments on the telephone communication system, Federated confirmed that its emergency response plan utilizes the telephone as the principle method of contacting residents in an affected area. It advised that it is continuously exploring new technologies for resident contact and is currently evaluating various options.

In response to the interveners' comments on public education, Federated advised that its public awareness steps exceed all requirements. After extensive public notice, information meetings were held in October 1991, and the nature of the project was explained to affected landowners, residents and public interest groups who chose to attend.

Federated also stated that its employees are trained for typical types of vapour releases and that they are made aware that each case is unique. It further advised that its exercises simulate varying conditions and locations to ensure that its staff are exposed to a variety of realistic situations for their response training.

5.3.3 Views of the Board

It is the Board's view that, in order to be effective, emergency response procedures must address logistical feasibility and be appropriate to the facility under operation. The ERCB's review of emergency response plans considers such matters prior to approving plans.

The Board believes that a consistent emergency planning approach results in efficient emergency response. It believes the 3 levels of alert used by Federated in its emergency response plan (ERP) are appropriate and consistent with current industry and government practices. The Board intends to contact industry to examine a co-operative emergency response process similar to that which exists for oil spills.

The Board recognizes the importance of adequate emergency response planning and training and has no reason to believe that the current level of industry training is inadequate, nor that it would be appropriate to raise accreditation requirements with APEGGA.

The Board also recognizes the importance of accurate resident information and emergency communication. It encourages Federated to include a backup notification method in its ERP, and to continue its research on improving methods for resident contact during emergencies. The Board believes it is extremely unlikely that both an electric power and telephone system failure would occur as the result of a pipeline failure without the local residents being well aware of the situation. However, in the event of disruption of electric power service battery operated radio may allow communication with residents through commercial radio announcements.

The Board does not believe that the CANUTEC Guideline is appropriate for application to pipeline situations.

With consideration for the above emergency response planning principles, the Board has reviewed Federated's ERP and finds it to be comprehensive and satisfactory.

6 ADDITIONAL CONCERNS OF LANDOWNERS

6.1 Gravel Pit Operations

6.1.1 Views of the Interveners

Mr. Puszkar and Mr. Tworek expressed concerns about the safety of their gravel pit operations. They complained that the existing pipeline was not marked when they were excavating for gravel, and that no response was received when they contacted Alberta 1st Call to locate the pipeline.

They said that they have made arrangements to supply gravel to purchasers. They were unable to proceed because of Federated's concerns about slope stability, the allowable amount of fill on top of the pipeline and the operation of heavy equipment over the pipeline. They also complained that the pipeline burial depth restricts further grading required for proper drainage in the area.

Both landowners indicated that they do not intend to continue their gravel pit operations if they have to assume responsibility for any consequence resulting from damage to the pipeline.

6.1.2 Views of the Applicant

Federated claimed that its routine inspection program would have indicated any on-going gravel pit operations on Mr. Puszkar's and Mr. Tworek's properties. Federated stated that it is a member of Alberta 1st Call and would have responded to any line locate requests. Federated submitted a list of phone calls made to Alberta 1st Call on and near the dates specified by the landowners which indicated that no recent phone calls were recorded respecting line locate requests.

Federated admitted that, although periodic aerial inspections are part of its surveillance program, it is possible that these aerial inspections could have missed the gravel pit activities if they were of short duration. Federated agreed to monitor more closely for unusual activities on or near its pipeline R.O.W. It also agreed to respond directly to Mr. Puszkar's and Mr. Tworek's line locate requests in the future.

Federated was not concerned about how much soil could be put on top of the pipeline and agreed to let the landowners excavate on either side of the R.O.W. as long as the R.O.W. is not disturbed. Federated also committed to work with the landowners to ensure that proper slope stability is maintained.

6.1.3 Views of the Board

The Board recognizes the landowners' concern about safety of their gravel pit operations in proximity to the pipeline. However, the Board is of the view that once the pipeline is marked, the gravel pit operators must be responsible for the safety of their operations. The Board notes that the Pipeline Act obligates people undertaking a ground disturbance around pipelines to ensure that no damage is done to the pipelines. However, the standard relating to pipeline operation and inspection also obligates the operator to maintain an awareness of public activities on or near the R.O.W., and to take such steps as are necessary to control access and prevent damage. The Board believes Federated should be more proactive in this regard in future.

The Board notes that Federated is willing to work with the landowners to ensure that proper slope stability is maintained on the pipeline R.O.W. around which gravel pit operations take place. The Board would require Federated to mark permanently the R.O.W. in the vicinity of the gravel pit to assist in establishing a safe distance for excavation activities.

6.2 Impact on Property Value and Future Land Development

6.2.1 Views of the Interveners

Mr. Puszkar and Mr. Tworek confirmed that when they purchased their properties a pipeline was already in place. Both Mr. Puszkar and Mr. Tworek were concerned about land devaluation because of the existing and proposed pipelines. They stated that their land has subdivision potential as it is included in the Big Lake Area Structure Plan. They argued that it would be more difficult to sell because of the HVP pipelines located on it. They were also concerned about the potential loss of revenue from restricted gravel pit operations.

6.2.2 Views of the Applicant

Federated generally did not have any comments on land values or future development plans in the area. It argued that the routing agreements signed by Mr. Puszkar and Mr. Tworek indicate their lack of opposition to the proposed route. Federated also stated that there are already two existing pipelines parallel to the proposed route, one of which is carrying similar HVP products, so there should be no significant additional impact.

6.2.3 Views of the Board

The Board notes that an HVP pipeline already exists on Mr. Puszkar's and Mr. Tworek's land, and believes that the addition of another line would have minimal, if any, effect on the value of the land.

7 OTHER MATTERS

7.1 Views of the Interveners

Mr. Morrison was concerned about the capabilities of current leak detection systems, the lack of computer software for pipeline failure analysis and the effectiveness of emergency communications. He asked Federated if it would be of value to organize a symposium to address these issues.

Ms. Young believed that employees with a substance abuse problem should not be involved in critical assignments. She suggested to the Board that it ensure that industry has a substance abuse program, as a requirement of the application, especially in critical areas where the public safety would be jeopardized.

Ms. Young contended that the use of the initials NGLs, as used to denote natural gas liquids, creates confusion for the public and even industry representatives in that they believe they stand for "natural gas lines." She emphasized the need to use different initials so that there would be a clear distinction between the two and proposed the adoption of the initials HVP for natural gas liquids.

Mr. Morrison supported Ms. Young's contention on the confusion between natural gas liquids and natural gas lines. He urged the ERCB to issue an information pamphlet explaining the characteristics and hazards of products being carried through pipelines and suggested that there should be clear notation on a certificate of title regarding the location of the pipeline and the nature and significance of the products being carried through the property.

7.2 Views of the Applicant

Federated stated that it would be willing to participate in a symposium of the nature suggested by Mr. Morrison to exchange information and ideas on either new development or existing technology.

Federated stated that it has an alcohol and drug abuse policy and that it sees no problem with providing that general information to the Board.

With respect to Mr. Morrison's suggestion of indicating pipeline locations and substance on land titles, Federated stated that pipeline easements are routinely recorded on land titles, but said it is incumbent on persons acquiring property to inquire into the specifics of the pipeline noted as the subject of a pipeline easement.

7.3 Views of the Board

The Board recognizes the interest and concerns of the public regarding safety matters relating to HVP pipelines and will consider the merits of advancing a symposium to address these issues. The Board will also initiate the development of an information document which will assist the public in understanding the nature and hazards associated with HVP products and pipelines and which will also clarify the difference between NGLs and natural gas lines. However, the initials themselves are used within the industry around the world. The Board will not attempt to define and implement special language for use in Alberta. The Board also notes that Federated has a substance abuse program and will not impose any additional requirements in this regard.

The Board recognizes the desire of the interveners that additional pipeline information be available on a certificate of title. It is the Board's understanding that it is not currently permissible to expand the pipeline information on a certificate of title. The Board will, however, further investigate this possibility. As previously stated, detailed information, further to that contained on a certificate of title, can be obtained from the ERCB or the operator.

8 DECISION

The Board has carefully considered the arguments presented by both applicant and interveners and is prepared to grant Application 920128 by Federated Pipe Lines Ltd. for the reasons discussed in this report, subject to the receipt of the approval of the Minister of the Environment respecting environmental matters, and subject to the conditions that

a) Federated shall notify the Tworeks in advance of each phase of construction in the vicinity of their dwelling.

b) Federated erect warning signs at intervals, to clearly and continuously mark the location of the pipeline through the Puszkar's and Tworeks' properties.

DATED at Calgary, Alberta on 10 August 1992.

ENERGY RESOURCES CONSERVATION BOARD

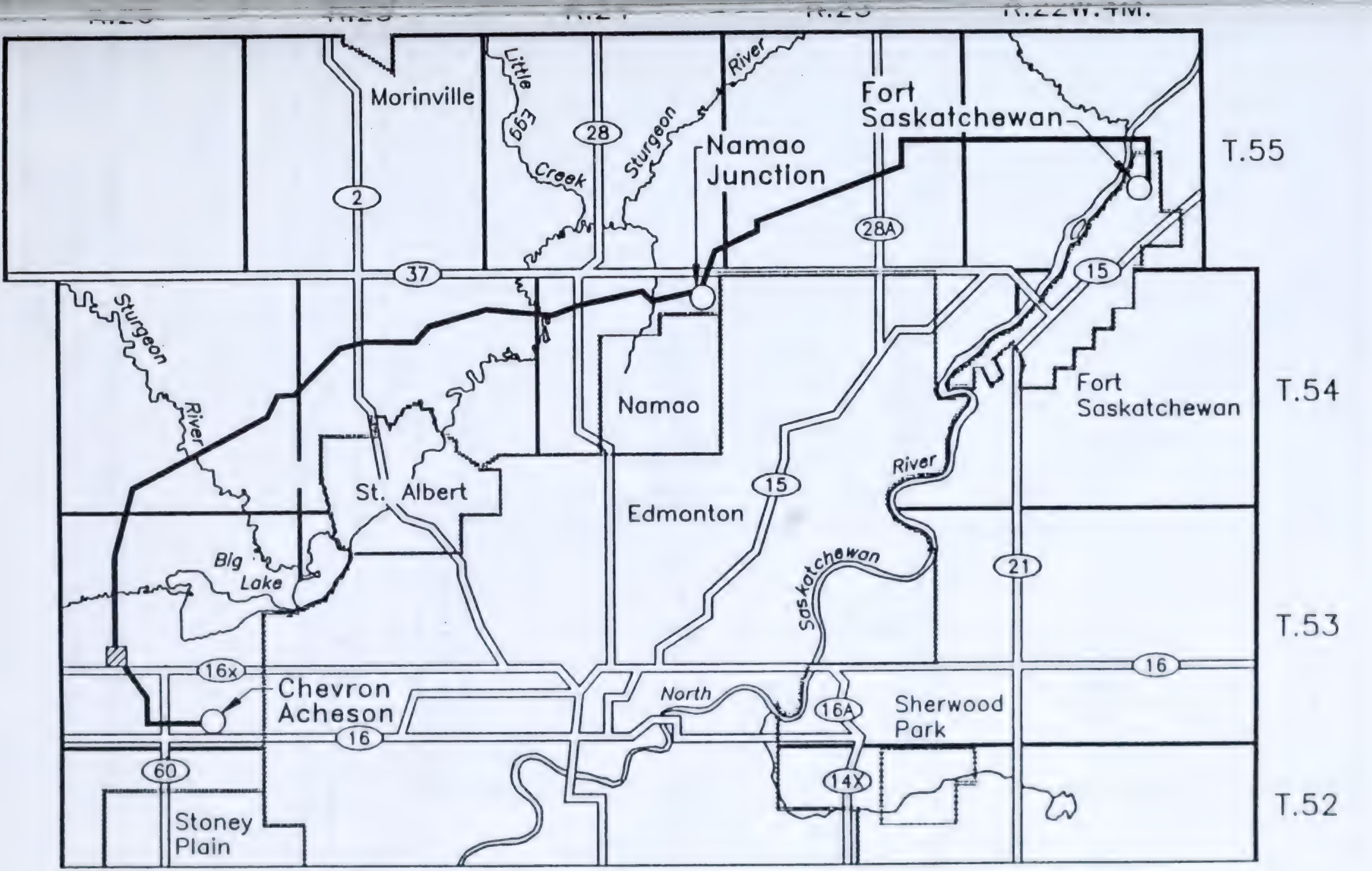
J. P. Prince

J. P. Prince, Ph.D.

R G Evans

R. G. Evans, P.Eng.

J. D. Dilay, P.Eng.



LEGEND

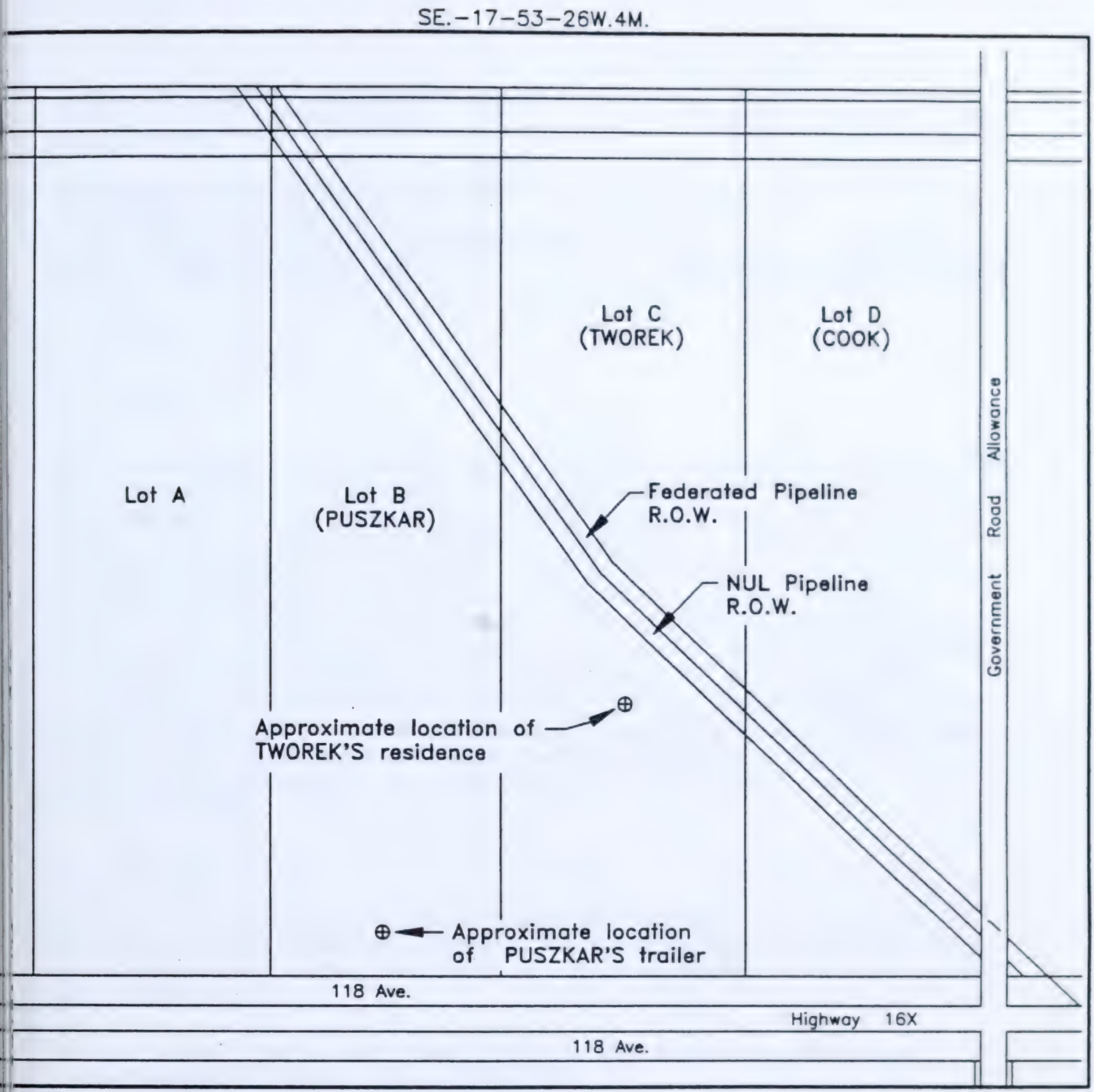
▨ Land Owned by Mr. Puszkar and Mr. Tworek

○ Plant Site

— Proposed Acheson–Fort Saskatchewan Pipeline

Figure 1
PROPOSED ACHESON TO FORT SASKATCHEWAN PIPELINE
Application No. 920128
Federated Pipe Lines Ltd.

D 92–3
ERCB



END

le = 1:5000

URE 2

OPOSED ACHESON TO FORT SASKATCHEWAN PIPELINE

DIVIDUAL OWNERSHIP PLAN (SE.-17-53-26W.4M.)

plication No. 920128

derated Pipe Lines Ltd.

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATIONS BY KOCH PIPELINES LIMITED FOR A PERMIT TO CONSTRUCT A CONDENSATE PIPELINE AND A PUMP STATION IN THE COCHRANE-MADDEN AREA

Decision D 92-4
Applications No. 920563 and 920623

1 INTRODUCTION

1.1 Application

Koch Pipelines Limited (Koch) applied (Application No. 920563) to the Energy Resources Conservation Board, pursuant to Part 4 of the Pipeline Act, for a permit to construct approximately 70 kilometres (km) of 168.3-millimetre (mm) Outside Diameter (O.D.) pipeline and a pump station. The proposed pipeline would start at a point located in Legal Subdivision 2 of Section 5, Township 24, Range 3, West of the 5th Meridian (Lsd 2-5-24-3 W5M) and would proceed to a tie-in point on the Home Oil Company Limited (Home Oil) Cremona Pipeline System located in Lsd 13-30-28-2 W5M in the Madden area. The proposed 225-kilowatt (kW) pump station would be located at Lsd 2-5-24-3 W5M. Further, Koch also applied (Application No. 920623) to reverse the flow of a 14.5-km long portion of the existing 114.3-mm O.D. pipeline from Priddis Junction through the Tsuu T'Ina Nation Reserve No. 145 to the starting point of the proposed pipeline (attached figure). The proposed system would transport condensate from Waterton, Jumping Pound, and Wildcat Hills gas plants. If the applications are approved, Koch plans to deactivate the existing 168.3-mm and 114.3-mm O.D. pipelines from Priddis Junction through Calgary to the connection with the Cremona Pipeline located at Lsd 12-36-23-1 W5M.

1.2 Hearing

The hearing was changed from an Examiner hearing to a Board hearing and all parties were advised. The hearing was held in Calgary on 23, 24, and 25, June 1992 and reconvened on 29 and 30 June 1992, before Board Member N. G. Berndtsson, P.Eng., and Acting Board Members W. G. Remmer, P.Eng., and H. O. Lillo, P.Eng.

The Board members, applicant, and interested interveners visited various parts of the existing, proposed, and alternate pipeline locations on 30 June 1992.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Koch Pipelines Limited (Koch) K. Miller	R. C. Aldridge F. Jensen, P.Eng. D. Williams, P.Eng. R. Evans, P.Eng. B. W. Mitchell R. Nowak, Ph.D., P.Geol.
G. L. MacDougall	G. L. MacDougall
D. Griffin R. Neufeld L. Stewart	D. Griffin D. L. Dabbs, P.Ag., P.Biol. J. Bonnett A. L. Mackay
TransAlta Utilities Corporation (TransAlta) C. Meagher	R. McRorie
J. Curtis	J. Curtis
Elbow River Ranch Limited W. Copithorne	W. Copithorne
Brian and Robert Copithorne	B. Copithorne
Roy Copithorne R. Neufeld L. Stewart	R. Copithorne D. L. Dabbs, P.Ag., P.Biol. J. Bonnett A. L. Mackay
Town of Cochrane (the Town) M. Schmitke	M. Schmitke
G. A. McKendrick Ranches Ltd. (McKendrick Ranches) G. McNabb, P.Eng.	G. McNabb, P.Eng.
Simpson Ranching Limited (Simpson Ranching) J. Ballem	J. Simpson
Shell Canada Limited (Shell) E. Decter R. Reigert	B. W. Mitchell

THOSE WHO APPEARED AT THE HEARING (cont)

Home Oil Company Limited (Home Oil)	
D. McCoy	M. Massecar, P.Eng.

Alberta Environment
H. Slavinski

Energy Resources Conservation Board staff
M. J. Bruni
K. J. Bahadur
R. W. Longley

2 ISSUES AND PRELIMINARY MATTERS

The Board considers the issues to be

- need for the pipeline, and
- route selection and impact.

The attached figure shows the proposed, alternate, and existing pipeline routes in the area. For convenience, the pipeline route map has been divided into Sections A, B, C, and D. Section A refers to the route from Priddis Junction to just south of the proposed pump station. Section B is the route from the proposed pump station to north of Highway 1. Section C refers to the route from Highway 1, north to the intersection of Highway 22, and Section D refers to the route from the intersection of Highway 22 to the tie-in point in the Madden area.

Koch introduced the future transportation of crude oil, in addition to the identified condensate volumes, as further support of the new pipeline. However, this scenario was advanced in response to the Board's examination of the pipeline design and was not included in the application. Some interveners questioned its admissibility and further argued that they were not in a position to immediately respond to the relevance of Koch's proposal. The Board ruled at the hearing that it would consider the application for transporting condensate as filed and could only give appropriate weight to future opportunities as brought forward by Koch at the hearing. It stated that if Koch chose to amend its application to have the Board consider the future transport of additional volumes, evidence on the future opportunities would be required. In response to the Board's ruling, Koch chose not to provide further information on potential crude oil transport opportunities.

3 NEED FOR THE PIPELINE

3.1 Views of the Applicant

Koch stated there was a need to transport condensate from the Waterton, Jumping Pound, and Wildcat Hills gas plants to Alberta refineries. It also acknowledged that the condensate production from these plants would decline over time.

The applicant indicated that it is necessary to construct a new pipeline because portions of the existing pipeline are located within the City of Calgary and should be discontinued due to the risk of damage and the need to upgrade the pipelines.

Koch indicated that the two parallel pipelines, now located close to densely populated areas within the city, were constructed in 1929 and 1933. The pipelines share space with utilities and roads and their right of way is frequently disturbed by construction activity. Some sections of the pipelines have been relocated and upgraded due to construction activity. As an example, Koch indicated that it had received 1215 line location requests in 1991. Koch stated that the advanced age of these pipelines, the sharp bends in the line, and the welding techniques used at the time of construction made it impossible to utilize internal electromagnetic inspection tools to confirm the integrity of the pipeline. In response to questions about trucking the condensate as an alternate to using the pipeline through Calgary, Koch stated that it was feasible but it preferred to have a new pipeline route west of Calgary to move the condensate.

Koch stated that upon approval of the subject applications, it would discontinue operation of the existing pipelines through the City of Calgary.

3.2 Views of the Interveners

Representatives of Simpson Ranching and McKendrick Ranches contended that the existing pipeline segment through Calgary was safe to operate and had been operating safely for many years. They suggested that the proposal to deactivate these pipelines and to re-route them was without merit. Simpson Ranching stated that there was no legislative or regulatory mandate requiring the pipeline to be moved from densely populated areas. In fact, it observed that Koch operates pipelines in densely populated areas elsewhere. Simpson Ranching noted that the condensate production is forecast to decline in the near future and no new volumes would be transported by the proposed pipeline; therefore, the project should not be approved. The representative for Glen MacDougall, Dwayne Griffin and Roy Copithorne, argued that the existing system was more efficient and less disruptive than the Koch proposal. He stated that the proposed pipeline construction would be disruptive to the community and the environment, particularly in the Elbow River Valley area.

3.3 Views of the Board

The Board recognizes that urban encroachment has led to dense population and significant activity very close to the Koch condensate pipelines within the City of Calgary. It also recognizes that these pipelines share space with numerous utilities and the high level of construction activity has increased the potential for third party damage to the pipeline.

The Board believes that, over the long term, condensate from the Waterton, Jumping Pound, and Wildcat Hills gas plants should be transported by pipeline. While the Board believes that condensate pipelines can be properly designed, located, and operated within urban areas, there must be measures in place to protect the pipelines and ensure their integrity. The Board agrees with Koch that the integrity of the pipelines within the City of Calgary cannot be adequately confirmed by electromagnetic inspection.

The Board agrees that, given the location of these pipelines, significant construction activity near the pipeline, and the difficulty of confirming integrity, it is prudent to consider relocation of the pipelines if an appropriate route can be selected.

4 ROUTE SELECTION AND IMPACT

The applicant outlined general route selection criteria and presented preferred and alternate routes for various sections of the pipeline route. Some interveners questioned the applicability of the criteria and all interveners expressed views on the routes that impacted their lands. The views of the applicant and interveners on the route criteria are summarized below, followed by their views on the preferred and alternate routes in Sections B and C. The Board's views on the criteria and routes are outlined in Section 4.2 below.

4.1 Views of the Applicant and Interveners

Selection Criteria

The applicant, with the assistance of Shell, indicated that the daily peak volumes of condensate to be transferred were 1200 m^3, 400 m^3, and 50 m^3 for the Waterton, Jumping Pound, and Wildcat Hills gas plants respectively.

Koch proposes to transport the Waterton condensate north by reversing the flow of the existing 114.3-mm line from the Priddis Junction to a proposed pump station at Lsd 2-5-24-3 W4M (Section A, attached figure). The Waterton condensate would then be combined with the Jumping Pound and Wildcat Hills condensate and transported in a new 168.3-mm pipeline connecting to the Home Oil Cremona Pipeline System in the Madden area.

The applicant stated that the pipeline route selection criteria primarily focused on addressing landowner concerns, and landowner consultation took place both collectively and on individual bases. All through this process it assigned the highest priority to addressing landowner requests and concerns.

The applicant described the various corridors considered for the transportation of the condensate, including corridors within the Calgary Restricted Development Area. It emphasized that one of its reasons for constructing a new pipeline is to locate the pipeline away from highly populated areas. Therefore, the corridors within Calgary were not acceptable. Other corridors, east of Cochrane and east of Highway 22, were excluded due to present and planned residential developments in these areas. The applicant stated that the right of way selection criteria included: paralleling or occupying existing energy transportation corridors; complying with separation and easement set backs from occupied residences, dwellings, and public facilities; accommodating specific requests from landowners and occupants for location of the pipeline; avoiding planned residential developments; crossing such features as roads, road allowances, other pipelines, ditches, permanent water courses, and sharp topographic breaks at 90°; avoiding defined wetlands, springs, ponds, and drainage ditches; avoiding known heritage value sites; avoiding horizontal gradients greater than 10 per cent within the right of way; and, where the above do not apply, taking the shortest distance between locations.

Glen MacDougall, Dwayne Griffin, and John Simpson implied through their testimony that Koch had not met its design criteria of avoiding defined wetlands, springs, ponds, and drainage ditches, as it related to their respective lands. They stated that the construction activity could seriously impact the springs on the MacDougall land, the water wells on the Griffin land, and the "swampy" area on the Simpson land.

Route Selection

The impact of Koch's preferred and alternate routes, as well as options involving the use of pump station(s) and various combinations of existing and new pipeline construction for Sections B and C, as shown in the attached figure, were subject to extensive discussions during the hearing. No specific concerns were raised by the interveners about the impacts in Sections A and D. The proposed pipeline in Section D follows existing pipeline right of way.

Routes in Section B

As shown in the attached figure, Section B includes a pump station containing 3 x 75 kW electric drive pumps, an existing 114.3-mm pipeline transporting the Wildcat Hills and Jumping Pound condensate southeast to the pump station, and a preferred and an alternate route for the pipeline to transport the product north to Madden. Koch stated that the preferred configuration had flexibility for "future business opportunities" to transport crude oil, but acknowledged this scenario was not part of the existing application.

The interveners questioned the need for the new pipeline, in part because the alternate route includes transporting the Wildcat Hills and Jumping Pound condensate south through the existing pipeline to the proposed pump station, and then pumping this condensate back north in a new pipeline located adjacent to the same (existing) pipeline. Under cross-examination by the Board, Koch outlined operating conditions for various scenarios including reversal of flow in the existing line, relocation of the existing pump station, and/or the addition of another pump station. Koch indicated that it would be possible to reverse the line flow in Section B and transport the Waterton condensate to at least a point north of Highway 1.

Preferred Route - Section B

Starting at the proposed pump station, Koch outlined the rationale for selecting the preferred route in Section B. Koch stated that the route, which parallels Highway 8, would avoid future residential development. It stated that it would undertake mitigative measures to avoid disruption of the springs on the MacDougall land. It would establish monitoring programs before, during, and after construction of the pipelines to minimize the risk of contamination of these springs. Glen MacDougall objected to the preferred route in Section B. He stated that if the pipeline was to go across Section 11-24-2 W5M he would have serious concern, because it could open a new corridor in this section. Also, a series of springs that are about 400 metres (m) north and parallel to the proposed pipeline, could become contaminated, or stop flowing. If the applicant follows the alternate route along the Amoco Rangeland right of way in section 12-24-4 W5M of his land, he would not have any objections.

The preferred route would deviate from the existing pipeline rights of way and follow TransAlta's power line right of way traversing section 15-24-4 W5M. The southwest quarter of this section contains the TransAlta substation and Dwayne Griffin's property. On the Griffin property, Koch would employ proper design, construction, and mitigative measures to minimize the risk of contamination of the water wells. Dwayne Griffin stated he plans to build a new house that would be very close to the proposed preferred route. The location of the house is dictated by its proximity to an existing water well and the municipal set back distance from the road. The proposed route would require that a number of mature trees be removed north of the building site. He stated that the other alternatives such as sharing the existing rights of way should be considered.

Alternate Route - Section B

In Section B the applicant presented an alternate route which would parallel the existing pipeline rights of way. The applicant stated that south of the Elbow River, the alternate route passes through existing residential development. The river crossing traverses a wide flood plain, making it more difficult and less desirable from an environmental viewpoint, when compared to the river crossing on the preferred route. Koch did not comment on Brian Copithorne's suggestion for another route around his property.

John Curtis, Bill Copithorne, and Brian Copithorne all stated that the alternate route would have substantial environmental impact on this area. The area on the north bank of the Elbow River, along the proposed alternate route, has mature trees which would have to be cut down to make way for the pipeline. The interveners further stated that two rights of way already exist in this area and a third proposed by Koch would create irreparable environmental damage, particularly at the Elbow River crossing. Brian Copithorne stated that the construction activities would affect his cattle operation and that the land would be adversely affected, considering it is virgin soil. Brian Copithorne also stated that he preferred the route to travel along the road allowance on the western edge of the northwest quarter of Section 22, southwest quarter of Section 27, and northwest quarter of Section 27 all in Township 24. This is an established pipeline corridor which follows section lines between landowners and along the road allowance. The three interveners stated that the preferred route is better than the alternate route.

The representative for Glen MacDougall, Dwayne Griffin, and Roy Copithorne argued, based on the cross-examination and evidence presented at this hearing, that the need to construct a new pipeline in the Elbow River Valley area had not been clearly established. Koch's objective, to transport condensate to Madden, could be accomplished with much less disruption to the community and the environment by utilizing the existing Koch pipeline system and reversing the flow to north of Highway 1. Also, it would be more economic to reverse the flow in the existing Koch system as far as Highway 1 and eliminate the construction of 10 to 12 km of 168.3-mm pipeline in the Elbow River Valley area.

Routes in Section C

Preferred Route - Section C

In Section C of the attached figure, approximately 2.5 km north of Highway 1, the preferred route approaches the Tower Ridge Estates development. To avoid crossing this development, the applicant proposed the route cross the county road and into Roy Copithorne's land in Section 9-25-4 W5M, where the pipeline would run adjacent to the west side of the road allowance. The applicant eliminated the alternative of placing the pipeline in the road allowance in this area because the M.D. of Rockyview may require the pipeline be relocated in future. The applicant further stated that the option of placing the pipeline on the east side of the county road and the two existing pipelines in Section 10-25-4 W5M, placed the pipeline too close to an existing residence within the Tower Ridge Estates.

The applicant stated that, although pipeline construction may have some adverse affect on the elk ranch operation of Roy Copithorne, there are no plans for expanding the elk ranch for at least the next five years. Further, Roy Copithorne cannot build any facilities of a permanent nature for elk ranching within 60 m west of the road allowance; therefore, the preferred route would not infringe on his elk operation. Roy Copithorne stated that the proposed route on his land would impact his elk and cattle ranching operation. He would prefer the pipeline be placed in the road allowance and be buried deeper to accommodate future road construction. He stated that the M.D. of Rockyview has indicated that the road was not scheduled for upgrading or expansion in the future. He believed that the M.D. of Rockyview would be prepared to consider allowing the pipeline in the road allowance.

As an undertaking from the hearing, Koch followed up on Roy Copithorne's suggestion that the M.D. of Rockyview would be receptive to placing the pipeline in the road allowance without a condition that it may have to be relocated if the road is upgraded. Koch advised after the hearing that its application to the M.D. of Rockyview resulted in no change to the M.D.'s position.

The applicant stated that the proposed route adjacent to the Amoco Rangeland right of way on McKendrick Ranch would avoid populated areas in Cochrane. Although there are existing parallel rights of way for Nova, Imperial Oil, and Amoco just west of Cochrane, the applicant viewed these as unfavourable options because of their close proximity to the populated areas in Cochrane.
Grant McNabb, on behalf of McKendrick Ranches, stated that the ranch is opposed to the preferred route proposal and would not want the pipeline in the middle of the ranch. He argued that this would result in the land being wasted and impairing its use for future generations. The Town stated it preferred that the southwest fringe area not be utilized for a pipeline route since this area was marked for development in the future. The Town stated that if the Board was to approve one of the two routes proposed by Koch, the preferred route through the McKendrick land was best suited for the town's needs.

The preferred route would proceed through the McKendrick Ranch and into the Simpson Ranches to a point in Section 1-27-5 W5M. The applicant stated that traversing the Simpson land would not present any construction problems. Specifically, the risk of contamination of the water table would be minimized, if not eliminated, by proper design, construction, and mitigative measures. The route would turn east and parallel the Amoco ethane pipeline right of way in Section D to the tie-in point in Madden. John Simpson, on behalf of Simpson Ranching Ltd., argued that the route on his land was selected by Koch when a route to Sundre was first proposed and is no longer warranted. He stated that using his land was not the most direct route to Madden; therefore, the use of his land was unnecessary. He stated that the proposed pipeline could potentially contaminate the water table on a portion of his land, and added that this was a "swampy" area and construction could be difficult and was not desirable. Simpson Ranching favoured the "TransAlta Crossing Alternate" proposed by Koch because it avoided any use of the Simpson land. John Simpson observed that approximately 5 kilometres (km) of pipeline construction could be saved if the applicant's alternate route was selected.

Alternate Route - Section C

The applicant presented an alternate route in Section C which would start south of the Stoney Indian Reserves No. 142, 143, and 144 and would cross the Bow River following the existing TransAlta power line. This route is known as the "TransAlta Crossing Alternate" and would be in the road allowance adjacent to the McKendrick Ranch in Section 8-26-4 W5M. The alternate route would join the preferred route in Section 4-27-4 W5M and proceed to the tie-in point in Madden.

Grant McNabb stated that, if the Board was to approve the alternate route in this area, he would prefer that the pipeline be placed in the road allowance to the east side of the ranch boundary. He argued that public land (i.e. road allowance) along the ranch's eastern boundary should be used for a public project such as the one proposed by Koch. However, he stated that the eastern boundary of the McKendrick Ranch could be used, provided the right of way was limited to a 5 m width.

The Town stated that the alternate route was least preferred because of the close proximity of the pipeline to future development. The Town emphasized that it has marked the area on the western boundary to be developed in the next 10-year period, and would not like to see a pipeline in the road allowance next to the development.

The Town presented another alternative by indicating its preference would be for Koch to use the existing pipeline to the Wildcat Hills plant and construct a new pipeline from the plant east to the tie-in point in Madden. It was further stated that this alternative would minimize the river crossings. It stressed that the applicant's preferred and alternate routes were too close to the town's water supply and, in case of a rupture or leak, the water source would be contaminated before mitigative measures could be implemented.

4.2 Views of the Board

The Board agrees with many of the principles of Koch's route selection criteria; however, it had some difficulty, given the evidence provided, in determining how the criteria were consistently applied to the preferred and alternate routes. The Board believes that landowner input is key to developing viable options. There were several examples during the hearing where the Board believes that, had the dialogue continued between Koch and the intervener, acceptable route agreements may have been obtained. It is the Board's view that further efforts are warranted to attempt to resolve outstanding landowner concerns.

The Board also had difficulty in weighing the relative impacts of the preferred and the alternate route suggested by Koch and the interveners because there was insufficient evidence to compare the costs-benefits and impacts. In addition, the Board believes that Koch should demonstrate that, prior to creating impacts through additional pipelines or pump stations, it has optimized the use of the existing pipeline (e.g. additional flow reversal) given the condensate volumes outlined in the application.

In order to assist with the continuing discussions, the Board's preliminary views on the routes and impacts for Sections B and C are outlined below. The Board agrees with the flow reversal in Section A and with following the existing pipeline routes in Section D.

Section B

The Board believes that Koch should evaluate additional pipeline configurations for transporting the applied-for condensate volumes. These could include additional flow reversal and/or the siting of one or more pump stations. The Board believes there needs to be more evaluation of the relative impacts of one or two small pump stations compared with a major river crossing and/or several kilometres of pipeline.

The Board also reaffirms the principles of ERCB Informational Letter IL 80-11 regarding the sharing of pipeline rights of way. The Board observed, that in some cases, there appeared to be considerable space available in existing rights of way. Should a new pipeline be required, Koch should actively pursue the sharing of rights of way with other operators, which could result in minimal tree clearing, or in increasing the separation distance between the pipeline and occupied dwellings.

Where it is necessary to construct a new pipeline and there is a potential to impact groundwater springs, short-term and long-term mitigative and monitoring measures should be established in conjunction with the landowner.

Section C

Should it be necessary, following evaluation of options, to construct a new pipeline north from the area of the intersection of Highway 1 and the existing Koch pipeline (see attached figure), then the Board believes that Koch should enter into more dialogue with the impacted landowners.

The Board believes that consideration should be given to utilizing existing rights of way or burying the new pipeline deeper in the road widening set back adjacent to Roy Copithorne's land. With respect to the Simpson and McKendrick ranches and the Town, the Board is of the opinion that the alternate route listed as the "TransAlta Crossing Alternative" in Township 26 and part of 27, including the placement of the pipeline adjacent to or within the road allowance between Section 8 and 9-26-4 W5, should be given serious consideration by Koch and the adjacent landowners.

Conclusion

In conclusion, the Board believes that Koch must further evaluate options to ensure it has adequately addressed measures to minimize the impact on landowners and the environment. In so doing, Koch should involve impacted landowners to the greatest extent possible and the Board urges landowners to take part in the process.

5 DECISION

Considering the evidence presented at the hearing, the Board is not prepared to grant Applications No. 920563 and 920623. The Board will defer its decision until further evidence as discussed in the report, or an amended application, is submitted by Koch. The Board may reopen the hearing to consider any such submissions.

Dated at Calgary, Alberta, on 7 October 1992

Energy Resources Conservation Board

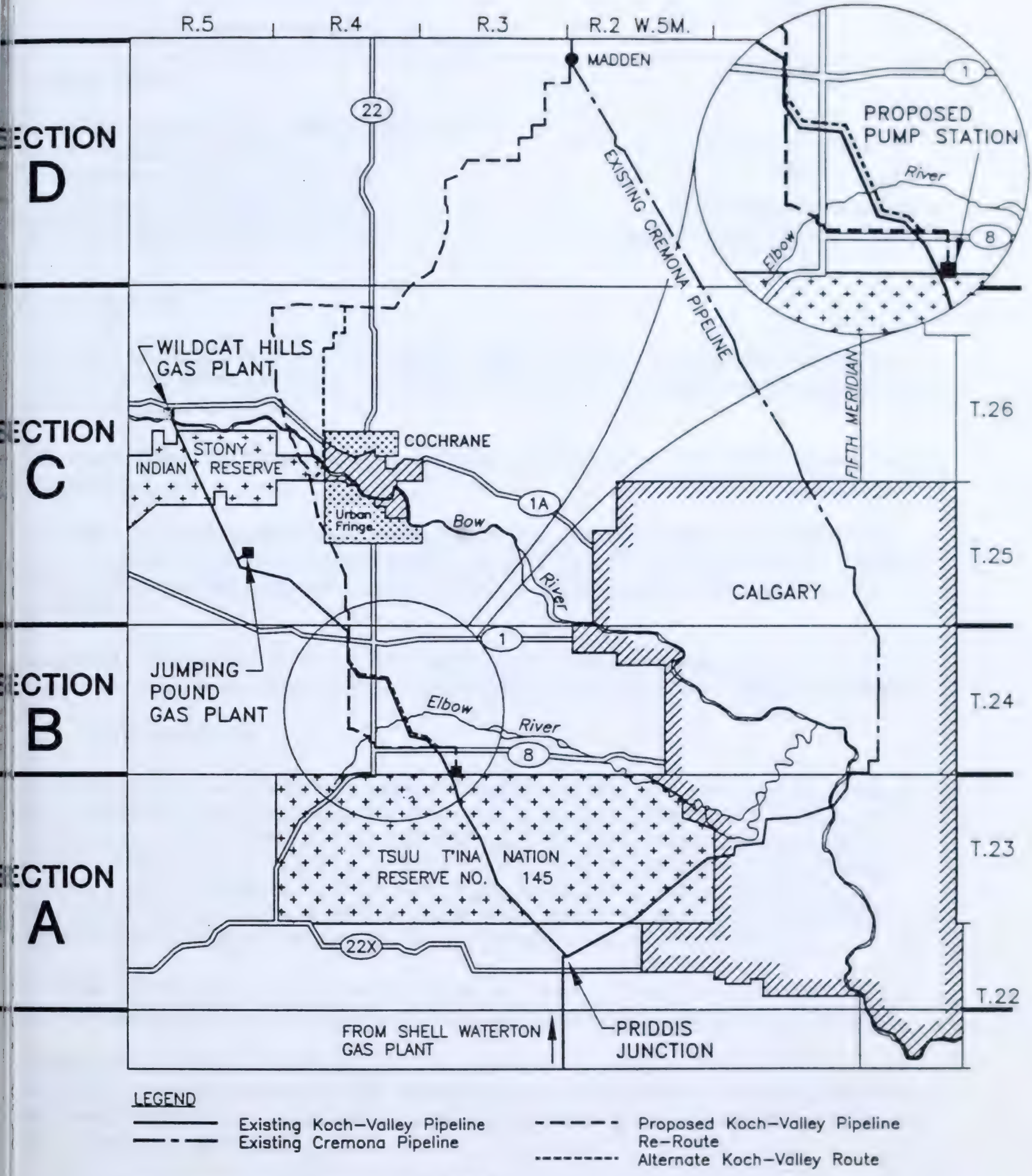
N. G. Berndtsson, P.Eng.
Board Member

WRemmer

W. G. Remmer, P.Eng.
Acting Board Member

H. O. Lillo

H. O. Lillo, P.Eng.
Acting Board Member



COCHRANE – MADDEN AREA
Application No. 920563 & 920623
Koch Pipelines Ltd.

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATIONS BY KOCH PIPELINES LIMITED FOR A PERMIT TO CONSTRUCT A CONDENSATE AND CRUDE OIL PIPELINE AND A PUMP STATION IN THE COCHRANE-MADDEN AREA

Addendum to Decision D 92-4
Applications No. 920563 and 920623

BACKGROUND

The Board indicated in Decision D 92-4, issued 7 October 1992, that it would defer its decision on Applications No. 920563 and 920623 until further evidence or an amended application is submitted by Koch Pipelines Limited (Koch).

The Board believed that further discussions with landowners were necessary to obtain acceptable route agreements.

The Board also indicated that prior to creating impacts through additional pipelines or pump stations, Koch should optimize the use of existing pipelines given the applied for condensate volumes. Crude oil transportation was briefly discussed at the June 1992 hearing but was not considered as part of the application.

The Board concluded Decision D 92-4 with a request that Koch further evaluate options to ensure measures to minimize the impact on landowners and the environment have been adequately addressed.

1 INTRODUCTION

Koch submitted an amended application dated 26 February 1993 to include future crude oil shipments and a revised pipeline route adjusting the alternate route in the original application as shown in the attached figure. The preferred route in the original application was no longer under consideration. The proposed route now includes: utilizing an Amoco Canada Pipeline right-of-way at the Elbow River crossing (section B), bypassing the Tower Ridge Estate Development to the east to avoid both the development and Roy Copithorne's land, and placing the pipeline in the McKendrick Ranches' lands adjacent to the road right-of-way along the Town of Cochrane's west boundary (section C).

A notice dated 22 March 1993 to reopen the hearing on 27 April 1993 was sent to all parties along the proposed pipeline route, as well as to all parties that participated in the original hearing in June 1992.

Landowner interventions to Koch's amended route were resolved prior to the 27 April 1993, however the Board decided to reopen the June 1992 hearing in order to confirm the need, given the potential for additional transportation of crude oil volumes and to ensure the design and route would create the least impact over other alternatives.

The hearing was re-opened in Calgary on 27 April 1993 with Board Member N.G. Berndtsson, P.Eng. (Chairman), and Acting Board Members W.G. Remmer, P.Eng., and H.O. Lillo, P.Eng. sitting to consider evidence directly related to the amended application.

THOSE WHO APPEARED AT THE HEARING REOPENING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Koch Pipelines Limited (Koch)	
K.F. Miller	D. William, P.Eng. D. Beach
Shell Canada Ltd. (Shell)	
E. Decter	
Federated Pipe Lines Ltd. (Federated)	
I. Maclean	
Energy Resources Conservation Board staff	
K.J. Bahadur R.W. Longley T.J. Pesta, P.Eng.	

Shell and Federated intervened in support of the application and did not present evidence at the hearing.

The Board rendered its decision at the conclusion of the hearing on 27 April 1993. This report confirms the oral decision.

2 NEED FOR THE PIPELINE

Koch reaffirmed the need to transport condensate from Waterton, Jumping Pound and Wildcat Hills and to discontinue the existing condensate pipelines through Calgary.

In addition, Koch indicated the proposed pipeline and pump stations may also be needed to transport approximately 480 cubic metres per day of crude oil from the Turner Valley area. By 1994, the Conoco refinery in Montana, USA, would no longer use this crude oil due to a change in feedstock requirements. Koch stated that there were no existing options to transporting the Turner Valley crude oil other than by the proposed pipeline or by trucking.

Koch indicated the proposed pipeline was designed to accommodate both the condensate and crude oil but it would be necessary to modify the system south of the proposed pump station in order to transport the crude oil to the pump station.

The Board still holds the opinion, stated in Decision D 92-4, that it would be prudent to discontinue the use of Koch's pipelines within the City of Calgary if an appropriate and acceptable route can be selected. The Board believes that it would also be appropriate to also include the possibility of Turner Valley crude oil in the pipeline design in order to avoid additional pipelines or trucking. The Board notes that additional modifications or facilities would be subject to future applications where a potential landowner or environmental impacts could be addressed.

3 ROUTE SELECTION AND IMPACT

Koch stated that the route now proposed considers environmental impacts, landowner concerns, construction implications, effects on pipeline operations and construction costs. The applicant highlighted its efforts in public consultation and stated there were no landowner or occupants opposing the project. Koch indicated that landowner preference was a significant factor in selecting the amended route.

Koch contended that a new pipeline crossing of the Elbow River was necessary. Pipelines hydraulics in either the condensate or crude oil scenario required the proposed pump station to be placed south of the Elbow River, thus necessitating a new river crossing. Koch believes it is not appropriate to significantly increase the operating pressures of the existing pipeline in the vicinity of the river crossing due to the age of the line and the environmental impacts of a spill should it reach the river. However, Koch stated that it would be possible to utilize the existing pipeline if the operating pressure was increased and pump stations were installed every 10 kilometres (km). Koch argued that the short-term environmental impacts of crossing the Elbow River were small in comparison to the impacts and higher costs of additional pump stations.

The Board considered the additional cost, impacts and pipeline options presented and agree that there is now clarity on the location of the proposed pump station and the need to install a new pipeline in section B.

The Board recognizes and appreciates the significant landowner negotiations undertaken by Koch. The Board believes that these discussions, although time consuming, have led to a more acceptable route.

The Board is satisfied that the pipeline routing and the pipeline design adequately balanced the need for a new pipeline with environmental and landowner concerns.

4 DECISION

This report confirms the oral decision given at the conclusion of the 27 April 1993 hearing. The Board approves Application No. 920563 as amended by Koch for construction of a pipeline and a pump station located in Legal Subdivision 2 of Section 5, Township 24, Range 3, West of the 5th Meridian, and Application No. 920623 for the flow reversal of an approximate 14.5 km portion of the existing 114.3 mm Outside Diameter pipeline.

The Board has referred the application to the Minister of Alberta Environmental Protection pursuant to section 8 of the Pipeline Act. The Minister's approval was received and pipeline permit issued 10 May 1993.

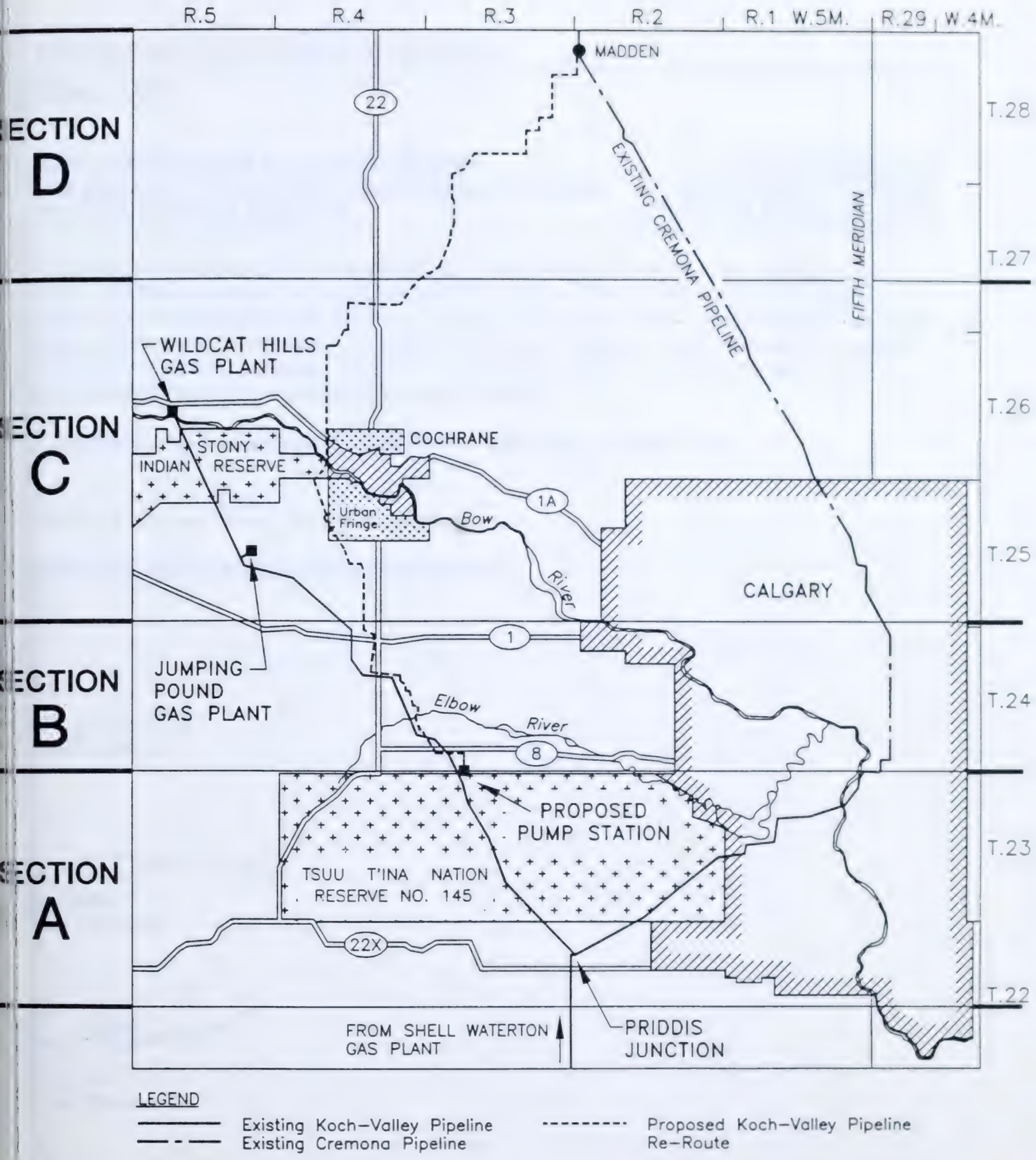
DATED at Calgary, Alberta on 15 June 1993.

ENERGY RESOURCES CONSERVATION BOARD

N.G. Berndtsson, P.Eng.
Board Member

W.G. Remmer, P.Eng.
Acting Board Member

H.O. Lillo, P.Eng.
Acting Board Member



COCHRANE – MADDEN AREA
Applications No. 920563 & 920623 (Amended)
Koch Pipelines Ltd.

Addendum to D92–4
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

NOVA CORPORATION OF ALBERTA (NOVA)
FOR PERMITS TO CONSTRUCT ADDITIONAL FACILITIES
TO NOVA WESTERN MAINLINE

Interim Decision D 93-1
Applications 921279, 921526,
921527, 921560, 921561, and 921562

The Board has considered NOVA's applications, and the evidence submitted at the hearing on the subject applications commencing on 12 January 1993. It is satisfied that the applied-for facilities are needed to provide incremental gas delivery capability to the Alberta-British Columbia border and in the long term interest of the province. Accordingly, the Board is prepared to issue the permits as applied-for by NOVA, without conditions, subject to receipt of the required approvals of the Minister of Environmental Protection respecting environmental matters.

A detailed report providing reasons for the Board's decision will be forthcoming.

DATED at Calgary, Alberta, on 2 March 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D.*
Vice Chairman

E. J. Mink
Vice Chairman

B. F. Bietz, Ph.D.
Board Member

---

* J. P. Prince, Ph.D. was unavailable for signature, but concurs with the contents and with the issuing of this Interim Decision.

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

NOVA CORPORATION OF ALBERTA
PERMITS TO CONSTRUCT ADDITIONAL FACILITIES
ON NOVA WESTERN MAINLINE

Decision D 93-1
Applications 921279, 921526, 921527
921560, 921561, and 921562

1 INTRODUCTION

1.1 Applications

NOVA Corporation of Alberta (NOVA) submitted to the Energy Resources Conservation Board (the Board), pursuant to Part 4 of the Pipeline Act, the following applications:

- Application No. 921279 for a permit to modify the existing Burton Creek compressor station located in Legal Subdivision 14 of Section 6, Township 12, Range 1, West of the 5th Meridian (LSD 14-6-12-1 W5M),

- Application No. 921526 for a permit to construct a 44-megawatt compressor station near Turner Valley in the south-east quarter of Section 15-20-3 W5M,

- Application No. 921527 for a permit to construct 24.9 kilometres (km) of 1067 millimetre (mm) outside diameter (O.D) pipeline, the Nelson Creek Loop, from LSD 16-22-14-2 W5M to a compressor station in LSD 14-6-12-1 W5M,

- Application No. 921560 for a permit to construct five additional meter runs at the existing Alberta - British Columbia (B.C.) Border meter station in LSD 12-11-8-5 W5M,

- Application No. 921561 for a permit to construct 11.9 km of 1067-mm O.D. pipeline, the Lundbreck Loop, from LSD 15-32-8-2 W5M to a pipeline in LSD 11-3-8-3 W5M, and

- Application No. 921562 for a permit to construct 7.3 km of 914-mm O.D. pipeline, the Crowsnest Loop, from LSD 15-31-7-3 W5M to a pipeline in LSD 9-4-8-4 W5M.

The above applied-for facilities (the facilities) are proposed additions to the NOVA Western Mainline natural gas pipeline system (attached Figure). Shippers have requested a total of 830 million cubic feet per day (MMcf/d) of incremental capacity. Since there is spare capacity of 30 MMcf/d in NOVA's existing system, it applied for a combination of additional facilities to provide 800 MMcf/d of incremental capacity at the Alberta - B.C. border. This incremental capacity was requested as the final component of a plan to export natural gas to markets in the Pacific Northwest (PNW) and California through a proposed expansion of existing facilities of Alberta Natural Gas Company Ltd., and Foothills Pipe Lines Ltd. in B.C.; Pacific Gas Transmission Company in Idaho, Washington, and Oregon; and Pacific Gas & Electric Company in California. The expansion proposal is collectively referred to in this decision report as the PGT Expansion Project.

1.2 Interventions and Hearings

Application No. 921279 was filed on 28 August 1992. A notice for objection was issued on 17 September 1992 and eleven interventions were received.

Applications No. 921526 and 921527 were filed on 22 October 1992 and 921560, 921561, and 921562 on 29 October 1992. Since these five applications and Application No. 921279 are all intended to deliver gas to the PGT Expansion Project, the Board decided to hold a single public hearing to consider all six applications.

A pre-hearing meeting was held in Calgary on 6 January 1993 to consider procedural and other related matters.

The hearing to consider the applications commenced on 12 January 1993, in Calgary, before Board Members J. P. Prince, Ph.D., F. J. Mink, P.Eng., and B. F. Bietz, Ph.D.

Those who appeared at the hearing and the abbreviations used in this report are listed in the attached Table.

The PGT Expansion Project, as well as a competing project proposed by Altamont, were the subject of an earlier Call for Information (Proceeding No. 911586). The evidence presented during that proceeding was incorporated into the record at the outset of the hearing.

1.3 Interim Decision

The Board issued an Interim Decision on 2 March 1993 approving the facilities, without conditions, subject to receipt of the required approval of the Minister of Environmental Protection respecting environmental matters. A copy of Interim Decision D 93-1 is appended to this report (Appendix A). This report provides the reasons for that decision.

2 ISSUES

The Board believes the issues to be addressed are:

- The relationship of the current facility applications to other regulatory procedures, including;
    - Information Letter IL 90-8, "Procedures for the Assessment of Nova Pipeline Applications - Industry Review", and
    - gas removal permits.
- The need for the facilities including;
    - criteria for establishing need,
    - gas supply and deliverability, and
    - nature and reliability of the market (short and long term).

- The possible adverse effects of the facilities for;
  - existing NOVA customers, and
  - landowners and the general public.
- The need for conditions relating to size and timing of the facilities.

These issues are addressed below.

3 OTHER REGULATORY PROCEDURES

3.1 Relationship Between Pipeline Facilities Applications and IL 90-8

3.1.1 Views of NOVA

NOVA argued that in accordance with IL 90-8, interested parties should have filed their concerns with the proposed facilities at the time the 1993-94 annual plan was filed in June 1992. The annual plan described NOVA's view of the optimum design and need for new facilities. By the time of the hearing, NOVA stated that it was too late to change the design and still meet the requests for service.

NOVA stated that the Board has consistently followed the procedures and criteria detailed in IL 90-8 in assessing NOVA pipeline applications. NOVA did not believe the Board should adopt new or modified criteria for the applications under consideration. This, in NOVA's view, would be unfair to NOVA and its customers who have organized their business affairs and incurred substantial financial obligations based on the understanding that IL 90-8 would be the Board's only criteria for evaluating NOVA applications. If the criteria for evaluation were to be changed from those set out in IL 90-8, this should be addressed in a generic process outside these specific facilities applications.

3.1.2 Views of Interveners

While a number of shippers supported NOVA's position on this matter, Altamont stated that if IL 90-8 was the only procedure to be used for the assessment of NOVA facilities, there would be nothing further to consider or decide once the NOVA annual plan had been filed except for landowner issues. This would imply that there could not be any event which might occur subsequent to the filing of the annual plan that might alter the design or need for facilities. Altamont stated that in this case, events had in fact occurred subsequent to the filing of the annual plan which might affect the need for the proposed facilities, and that reliance on only the annual plan was not appropriate.

ProGas stated that it had raised design concerns respecting the 1993-94 annual plan. Although NOVA had responded, ProGas' specific concerns regarding the impact of the applied-for facilities on system deliverability at Empress were not addressed (see section 4.2.2).

3.1.3 Views of the Board

While the Board certainly concurs with NOVA that those affected by the proposed facilities should indicate any concerns at the earliest opportunity, it does not accept the position advocated by NOVA and some shippers, and believes that they have misinterpreted IL 90-8, particularly Items J and K

(Appendix B). The Board has in fact followed the procedures and criteria set out in IL 90-8 for evaluating the facilities. The notice for objection for Application No. 921279 was issued in accordance with Item J and valid objections were received. Consequently, the hearing was set to consider all six applications concurrently (see section 1.2) in accordance with Item K of IL 90-8.

In any event, a public hearing must always remain as an opportunity to consider and address outstanding issues that are unresolved through the consultative process.

3.2 Relationship Between Pipeline Facilities Applications and Gas Removal Permits

3.2.1 Views of NOVA

NOVA noted that historically the process for obtaining pipeline facilities approvals and gas removal permits had been separate matters and it argued that these facilities approvals should not be linked to confirmed removal permits. NOVA suggested that if gas removal permits became a requirement for pipeline facilities approvals, it would have a serious effect on the length of time it took to add new facilities. NOVA also argued that the Board should not be bound to grant gas removal if it grants approval of the facilities permits applications. Any risk of stranded investment, should removal permits be subsequently denied, should fall on the shippers that requested the incremental capacity.

3.2.2 Views of Interveners

Altamont and Amoco submitted that it would be appropriate for the Board to grant approval only to those proposed facilities that were underpinned by firm sales arrangements, and which had gas removal permits and export licences in place by the proposed in-service date of the facilities. They expressed the view that both short and long term sales arrangements would meet this requirement.

Altamont and Amoco also argued that approval of the facilities in advance of removal permits, as requested, would infer that the necessary related gas removal permits would be forthcoming. Altamont suggested that the Board would be under pressure to grant gas removal permits after approval of the facilities, because shippers would be subject to demand charges for volumes that could not flow in the absence of gas removal permits.

Some shippers expressed the view that there should not be a requirement to have gas removal permits or export licenses in place before the Board approved the construction of the facilities. Two shippers noted that such a requirement would be unrealistic since buyers were unlikely to sign short term contracts so far in advance of gas actually flowing. Some shippers also noted that they had already received gas removal permits relating to the project, others indicated that they were in the process of obtaining gas removal permits, or that they expected to obtain such permits as required. In addition, some shippers argued that the Board would not be prejudging future applications for gas removal permits or implicitly granting such applications by approving the facilities.

3.2.3 Views of the Board

The Board notes that facilities applications and gas removal permits are considered under separate statutes. The Board is of the view that applications for facilities are separate and distinct from applications to remove gas from the province. In particular, in the event facilities are approved, the

Board will not give weight to any subsequent arguments to the effect that removal permits are now needed because of individual shipper's commitments with respect to the facilities. Any such commitments are at the risk of those who make them. Applications to remove gas from the province will continue to be assessed on their own merits against a test of overall public interest.

4 NEED FOR THE FACILITIES

4.1 Criteria for Establishing Need

4.1.1 Views of NOVA

NOVA submitted that the significant financial commitments from shippers should be accepted as establishing the need for the facilities.

NOVA noted it had executed a comprehensive Expenditure Authorization Agreement and Security Agreement backstopped by irrevocable letters of credit with PGT for a transportation capacity of 596.3 MMcf/d to commence service on 1 November 1993. The PGT agreement was on behalf of a number of shippers on the PGT Expansion Project. NOVA has also executed these same agreements directly with five shippers: Chevron for 53.1 MMcf/d; Esso for 52 MMcf/d; Norcen for 48.5 MMcf/d; North Canadian for 59.3 MMcf/d; and Petro-Canada for 20.2 MMcf/d. Total contracted capacity amounts to 829.4 MMcf/d. These agreements ensure that in the event that the construction of the facilities does not proceed to completion, the signatories to the agreements remain liable for all costs incurred by NOVA.

Pursuant to the terms of NOVA's Gas Transportation Tariff, the five shippers and PGT have also entered into 15 year irrevocable Firm Service Agreements with NOVA. These agreements specify that service is to commence on 1 November 1993. Demand charges are payable by shippers as of the billing commencement date which, at the earliest, is 1 November 1993 whether or not they have any gas flowing through the facilities. At that date, transportation rights will revert to the shippers on whose behalf PGT entered into the Firm Service Agreement.

4.1.2 Views of Interveners

The majority of the shippers on the PGT Expansion Project agreed with NOVA that long term irrevocable transportation agreements made them liable for demand charges and represented a clear indication of the need for the facilities. Furthermore, all shippers have made similar agreements with ANG and PGT, and some with PG&E as well.

Altamont believed that transportation contracts should constitute one of the criteria to demonstrate need for the facilities, but other factors, such as gas removal permits, should also be considered.

Amoco submitted that the willingness of shippers to pay for the facilities did not necessarily mean that such facilities should be approved. A demonstrated incremental market should also be a requirement for approval of additional facilities.

4.1.3 Views of the Board

In varying degrees, the supporters of the applications contended that the Board should accept the commitments of shippers to pay for the facilities through long term irrevocable firm service contracts and through expenditure authorization agreements, as sufficient evidence that the facilities are needed and in the public interest.

The Board can not agree completely with the positions put forward at the hearing. The Board is of the view that these private contractual arrangements can not be the exclusive test of the need for the facilities. The Board would expect that all applications for facilities involve parties who are willing to pay for them. That fact does not relieve the Board of its responsibility to determine need, on whatever basis it judges reasonable, in specific cases.

Although the Board will not accept private contractual arrangements alone as a sufficient demonstration of need, it does accept the somewhat less definitive position of some participants that these contractual arrangements represent a strong belief that the facilities will be needed.

The Board also does not consider the irrevocable transportation commitment on downstream facilities to be a reason to approve the necessary NOVA linkage to such facilities. The Board believes that the commitments on ANG, PGT, and PG&E were business decisions undertaken by shippers who should be solely responsible for any associated risks. In general, such contracts entered into by willing participants prior to consideration and approval of applications under existing legislation, are viewed by the Board as being entirely at the risk of those participants and not necessarily relevant to the assessment of the public interest. In the somewhat unlikely event that all other evidence before the Board leaves the Board undecided in a particular instance, the existence of such commitments may be considered.

The Board also believes, for major trunk line expansions involving long term transportation links to a new market, that it should satisfy itself that adequate gas supplies will exist to fill the line and that the market will absorb the gas in a reasonable time frame.

However, the Board does not accept Amoco's position that demand for facilities only be considered if it is incremental to existing markets.

The Board does not accept Altamont's position that removal permits should constitute one of the criteria to demonstrate need for the facilities, for reasons discussed in section 3.2.3.

4.2 Gas Supply and Deliverability

4.2.1 Views of NOVA

NOVA did not consider gas supply to be an issue with respect to the subject applications, and it did not examine the individual shippers' supplies in relation to the requested capacity addition. It noted, however, that there is more than enough total provincial supply to meet the requirements of the proposed project.

NOVA acknowledged that there had been insufficient deliverability to meet peak day demands on some occasions during this winter, however, it considered this to be due to individual shipper's deliverability problems and not reflective of a lack of overall reserves. In December 1992, NOVA implemented daily supply-demand balancing with each of its shippers and now has the ability to identify those shippers with shortfalls in deliverability. NOVA stated that it intended to work directly with those shippers in order to correct their inventory imbalance. Prior to daily balancing, all shippers were affected by deliverability shortfalls.

In response to questioning, NOVA acknowledged that in the hypothetical case where there was 100 percent of the contracted demand at the borders and all shippers had gas available to meet that demand, the existing system would allow NOVA to deliver only 98 percent of that supply to Empress. With the proposed facilities, only 94 percent of the total demand could be delivered to Empress as the larger gas volumes flowing west would affect remaining volumes flowing east. However, NOVA's experience had been that difficulties in meeting peak day demands were generally attributable to deliverability problems of individual shippers, as opposed to system limitations. NOVA also indicated that it had received customer support and would revise its system design criteria for the 1994-95 design year, in order to satisfy 100 percent delivery at all major delivery points and thus eliminate any system deliverability concerns.

4.2.2 Views of Interveners

A number of shippers submitted that the Board should consider whether there was adequate provincial gas supply available as one of the criteria used to determine need for the facilities. Shell also suggested that the Board should consider whether individual shippers have sufficient gas supply to justify the facilities.

Shipper-specific supply was not extensively explored at the hearing. Several shippers noted that they either had their own gas supplies in place for the project, that more supplies were being developed, or that negotiations were ongoing to arrange for supplies.

The majority of the hearing participants were of the view that there were adequate provincial gas reserves to supply the PGT Expansion Project. However, Altamont expressed concern that the Board had not specifically indicated in the report for Proceeding No. 911586 that reserves would be available for both the PGT Expansion and Altamont projects. Altamont submitted that regulatory policies should not be the cause of any one project achieving an advantage in terms of gas supply.

No party specifically expressed the view that the shortfalls in deliverability experienced by NOVA this winter were a result of a lack of overall reserves. Some shippers indicated that the shortfalls were due in part to mechanical problems.

The IGCAA argued that the deliverability problems should be understood before commitments were made that might make the problem worse or more difficult to resolve. The IGCAA asked the Board to fulfil its public interest mandate by looking into the delivery problems experienced this winter as part of a consolidated review of gas removal applications before allowing construction of the facilities.

ProGas submitted that the physical capacity of the other parts of the NOVA system, such as the Eastern Mainline system, should not be impinged as a result of construction of new facilities. It noted that in a situation where 100 percent of the supply were available, the physical capability of the entire

NOVA system to move gas to Empress would be reduced by 4 per cent, if the applied-for facilities were approved. ProGas suggested that solutions could include phasing in the increase in incremental capacity so as to minimize the impact on other parts of the system.

4.2.3 Views of the Board

The Board is satisfied that examination of gas supply on a provincial basis is appropriate to determining need for the facilities. The majority of participants submitted that provincial gas supply was adequate to supply the PGT Expansion Project without unduly affecting supplies within the province. On the basis of the Board's most recent estimate of the Alberta gas reserves available for inclusion in gas removal permits, the Board concurs that there are more than sufficient reserves on a provincial basis to support the facilities. The Board does not believe it appropriate to set aside reserves for possible future projects and expects project sponsors to address reserves issues as required.

With respect to deliverability, the Board understands the concerns of the IGCAA but does not consider the reported deliverability shortfalls experienced by NOVA this winter to reflect inadequate provincial gas supply. The Board considers it important that adequate deliverability exists to meet contracted commitments within Alberta, as well as for extra-provincial markets. It also considers it critical that pipeline facilities should be adequate to honour those commitments. It believes, however, that shippers and producers should be given an opportunity to address deliverability issues through the daily supply-demand balancing system, implemented by NOVA in December 1992, before any regulatory action on the matter is contemplated. In general, the Board considers arrangements between suppliers and industrial users to be a matter of private contract, and it would not normally interfere in contract disputes arising from the failure of a supplier to meet its contractual commitments. These disputes would be subject to a normal process through a court of law. However, the Board intends to monitor the situation and would be prepared to act should ongoing deliverability problems bring in to question the overall reliability of Alberta's gas supply system.

The Board concurs with the argument of ProGas that approval of the facilities should not be allowed to adversely affect the physical capability of the remaining NOVA system to deliver gas to Empress. It notes, however, that deliverability problems experienced to date have not been due to NOVA capacity design factors and that NOVA has made a commitment to meet 100 percent delivery at all major delivery points in 1994-95. The Board is satisfied that no further action on this matter is needed at this time but will expect NOVA to advise the Board of progress in resolving the problem.

4.3 Nature and Reliability of the Market

NOVA submitted no position on the market potential but relied on shippers on the PGT Expansion Project to support that issue.

4.3.1 Views of the Interveners

4.3.1.1 The Long Term Market

PGT submitted that the proposed NOVA facilities would provide service to two of the most promising US markets for Alberta-sourced gas; the PNW and California. Geographic proximity and favourable supply basin economics would aid Alberta producers to gain significant new market share in both regions. Most of the hearing participants agreed with this view.

PGT projected that the PNW gas requirements would grow from 926 MMcf/d in 1992, to 1135 MMcf/d in 1995, and to 1671 MMcf/d by the year 2011. The forecast incorporated the gas requirements projected by Portland General Electric Company as a result of its August 1992 announcement to shut down the Trojan nuclear generating facility in northwestern Oregon, by 1996.

PGT testified that shippers had entered into long term sales contracts with end-users in the PNW for a total volume of approximately 150 MMcf/d.

California is the second largest natural gas consuming state in the US, accounting for approximately 11 percent of the US total current gas consumption. PGT submitted a forecast of California's gas requirements (MMcf/d) as follows:

	1993	1995	2000	2011
Northern California	2542	2547	2626	3115
Southern California	3046	3307	3654	4346
Total California	5588	5854	6280	7461

PGT concluded from its analysis that demand for gas in California would support the long term need for the facilities. SoCal Edison, SDG&E and other southern California end-use customers had signed long term contracts with shippers for a total volume of approximately 260 MMcf/d.

Altamont acknowledged that PNW volumes might reasonably be expected to flow as would long term volumes contracted to markets in southern California. It argued, however, that out-of-state supply requirements into northern California gas markets would decrease from 1992 levels through 1995. Only modest growth is expected but not until well into the next century. Amoco urged the Board to determine whether a long term incremental market existed for the PGT Expansion Project volume and to examine California demand for natural gas.

4.3.1.2 The Short Term Market and Regulatory Uncertainties

The interveners generally agreed that there were many regulatory uncertainties including: the implementation of FERC Order 636, A&S restructuring, the California Public Utilities Commission (CPUC) decision on incremental tolls for PG&E expansion facilities, the imposition of the crossover ban and, the yet to be implemented intra-California capacity brokering. The open season for expanding PG&E existing Line 300, the proposed Mojave northward extension, and the CPUC's approval of discount transportation rates exclusively for Southwest US gas on the utilities system, to counter the threat of bypass due to the Mojave northward extension, were also included in this list of concerns. These regulatory uncertainties may all affect the short term viability of the facilities and most of these uncertainties will not be resolved before the proposed in-service date of 1 November 1993.

A number of shippers submitted that neither shippers nor end users in northern California were willing to sign long term contracts in the current uncertain regulatory and business environment. The majority of shippers indicated they were prepared to enter the northern California market on a short term basis. Although the issue of incremental tolling and the crossover ban were a concern, these shippers believed this would not necessarily impede their marketing effort. Some shippers pointed out that although they had hoped for rolled-in tolls at the outset of the project, they had been prepared to make a commitment to the project under incremental tolling. While the shippers were willing to proceed on the basis of incremental tolling, they expected to continue their active participation in the regulatory process to try and promote the least-cost option.

Some shippers testified that their decision not to finalize transportation contracts with PG&E was partly due to a desire to wait out regulatory uncertainties in California and partly due to a conscious business decision as to where they wished to meet their customers. In most cases, Malin was chosen to be the market centre for their short term gas sales. Other shippers indicated that their intentions were to work towards an agreement with PG&E, while leaving their options open to sell gas at Malin to end users with intrastate capacity. All shippers who appeared at the hearing stated that every effort would be made to ensure that gas would flow in order to avoid exposure to unabsorbed demand charges on facilities upstream of PG&E.

PGT stated that California appeared to lag behind a trend, in other US markets, to move to long term gas marketing arrangements. Regulatory uncertainty in California, along with a multiplicity of supply sources, were suggested to be the primary contributing factors. Until the restructuring of the existing arrangements between PG&E and A&S are concluded, PGT and shippers felt that it would be difficult for shippers to obtain long term arrangements in the northern California market. To date, PG&E has entered into firm transportation arrangements with shippers for a total volume of 300 MMcf/d. For the next two years, the remaining uncommitted capacity of the PG&E expansion, approximately 450 MMcf/d in California, will probably flow under short term arrangements. These short term arrangements will, in the view of PGT and some of the shippers, likely evolve gradually to longer term contracts.

PGT contended that the implementation of incremental tolling would not preclude the marketing efforts of shippers. The project was initially accepted by shippers on the basis of incremental tolling. The CPUC has recently agreed to eliminate duplicate charges on the PG&E expansion to northern California, resulting in lower rates than those originally approved. PGT emphasized that gas would not be stranded at Malin even in the absence of intrastate capacity brokering, a continuing crossover ban, or election by the shippers not to pay the incremental toll on the PG&E expansion facilities. On 1 November 1993, end-use customers of PG&E who have not signed contracts for the use of Line 401 (expansion in California to take away volumes delivered by the PGT Expansion Project) may still nominate for gas that PG&E may move on Line 401, but charge its customers according to the existing Line 400 rate schedule. Thus, gas would be able to flow even though PG&E would recover insufficient revenues from those end-users. PG&E stated that it would implement some type of end-use surcharge to cover these revenue deficiencies but details of the surcharge have yet to be worked out.

Altamont considered that recent regulatory events in the United States, and California in particular, had been adverse to the Alberta public interest to the extent that they had affected the economic viability of potential sales of natural gas into California by the PGT Expansion Project. While Altamont provided several examples of adverse regulatory behaviour by the CPUC, it highlighted incremental tolling on the PG&E Expansion and continuation of the crossover ban as representing significant impediments to the marketing of gas in northern California via the PGT Expansion Project. It doubted that the CPUC would, by November 1993, have rules in place for intrastate capacity brokering that would eliminate the need for the crossover ban. Altamont stated that this was the reason for the dearth of firm sales contracts by the PGT Expansion Project shippers to the California market, and for the fact that a number of shippers have yet to make firm transportation arrangements on PG&E.

Altamont also noted that whether the proposed Mojave northern extension is built or not, the very threat had caused discounts on certain PG&E transportation. This had the effect of locking out Canadian gas in the same manner as if the extension were built. Amoco also expressed concerns that the current discounting of certain tariffs on PG&E for US-sourced gas might already be locking Canadian gas out of the California market. Amoco requested the Board approve capacity only for markets that are clearly incremental to existing Canadian sales.

Czar noted that while regulatory interference by the CPUC was primarily directed at the PGT Expansion Project shippers, those on the existing system would also be affected. Incremental tolling reduces the PGT Expansion Project shipper netbacks. If these shippers sold gas for a lower price, the CPUC could find that this was also a reasonable price for existing gas sales to California. Czar recommended that all PGT Expansion Project volumes be prevented from moving until there was some reasonable resolution of what it viewed as discriminatory action against Canadian gas.

4.3.2 Views of the Board

The Board is cognizant of the complexity of the market in California and recognizes that the regulatory and market uncertainty present a fair degree of risk to those who wish to supply that market. However, the evidence submitted at the hearing showed that the shippers were willing to accept those risks.

With respect to the long term market, the Board agrees with the general position, maintained by most participants at the hearing, that the geographic proximity of the PNW and California make them promising US markets for Alberta's natural gas. Differences in view appear to relate to the market opportunity in the short term.

The Board notes that roughly one half of the applied-for capacity would be dedicated to markets that have entered into long term contracts and all parties accepted that gas was likely to flow to those markets starting in November 1993. The remaining capacity would be available to serve short term arrangements, most of which have not yet been consummated. All of the participants at the hearing acknowledged that some combination of long term and short term arrangements was acceptable, although there were apparent differences as to what proportion of long term versus short term arrangements would be appropriate.

The Board considers it unlikely that all volumes contracted to move in new facilities would be delivered under long term contracts. Given the current North American gas market, a more realistic expectation would be that gas would be delivered under both long and short term conditions, including some volumes of spot gas. The Board takes some comfort from the fact that long term contracts account for about one half of the applied-for capacity. The fact that the other half of the market is unwilling to enter firm contracts at this time is at least partly explainable by regulatory uncertainties and by the state of transition that characterizes associated commercial arrangements. Given the probability favouring long term prospects for Alberta gas in the western US market and the willingness of most of the shippers to accept the short term risks, the Board is satisfied that a need for the facilities has been demonstrated. To require firm contracts for short term sales at this time could well cause participants to enter into inefficient marketing agreements.

5 POSSIBLE ADVERSE EFFECTS OF THE FACILITIES

5.1 Impacts on Existing NOVA Customers

5.1.1 Views of NOVA

NOVA stated that there would be little or no adverse impact on existing NOVA customers as a result of the facilities, even if the facilities are not completed or utilized in a timely manner. The comprehensive Expenditure Authorization Agreements and Security Agreements have made shippers liable for all costs incurred by NOVA in the event that the facilities are not completed. Under the Firm Transportation Agreements signed, the demand charges for service are payable by the shippers whether or not these shippers are transporting gas on the system.

NOVA calculated the impact of the facilities on the system average unit cost. Even at a 40 percent average annual utilization of the facilities, there is no discernable increase to the system average unit cost-of-service. If load factors exceed 40 percent, existing NOVA customers would benefit from a reduced average unit cost-of-service.

5.1.2 Views of Interveners

While no one challenged NOVA's assessment of possible impacts of the new facilities on the cost of service to existing customers, there was some concern that new sales in California would require discount pricing and might cause those sales to be made at lower prices, implicitly displacing existing Canadian sales.

Altamont expressed the view that in order for Canadian gas to be competitive with southwest US gas, the commodity cost of the PGT Expansion Project volumes at the Canadian border would have to be discounted in the order of 40¢ US/GJ or 50¢ Cdn/GJ. The reason for this discount, Altamont stated, was that rates of PG&E to industrial customers in northern California can not, under the current rules, be discounted to match the by-pass rate expected to be offered by the proposed Mojave northern extension.

Amoco stated that Alberta supplies will be prevented from displacing southwest US gas because of the fact that utilities are only allowed to provide discount rates for US-sourced gas. Shell, on the other hand, testified that it currently had a long term market in California served by US-sourced gas. Shell intends to displace these volumes with Canadian gas. Norcen indicated that end-use customers in California, with whom it was currently negotiating, presently use southwest US gas. To the extent that these negotiations are successful, Norcen's sale of Alberta gas will displace these volumes.

Suncor testified that if any displacement of existing sales into California were to occur, it would be southwest US gas and not existing Canadian gas that would be displaced. It believed Canadian gas using existing PGT capacity will have an economic advantage over the PGT Expansion Project volumes due to the lower transportation rate on its existing facilities.

Washington Energy testified that it was now considering supplying a co-generation project in the PNW, due to commence operation 1 July 1993, off the PGT system. Initially, it anticipated to supply the project from its equity production of Rocky Mountain gas. DeKalb testified to a similar strategy. It is currently negotiating a sales agreement with a co-generation customer that DeKalb presently supplies from its California production.

5.1.3 Views of the Board

The Board accepts NOVA's evidence that contractual agreements with shippers will protect existing NOVA customers from adverse rate impacts even if the proposed facilities are not completed or utilized in a timely manner. In fact, the Board notes that existing customers may benefit from a reduced system average unit cost-of-service as the long term contracted sales volume alone, of 400 MMcf/d to the PNW and California, will exceed the 40 percent load factor.

In the case at hand, the Board is satisfied that Alberta gas can remain competitive in the California market and represent a strong supply option in that market for the long term.

With respect to increasing competition in the market, the Board takes a neutral stance. Any increase in competition would emerge because other sellers were willing to participate in the market. The Board would not normally attempt to limit competition through regulatory action.

5.2 Impacts on Landowners and the General Public

5.2.1 Views of NOVA

NOVA acknowledged that only two landowners had expressed concerns regarding the facilities.

NOVA stated that it believed its applications are technically sound. It completed a detailed review of the proposed Turner Valley compressor station site and found that it had a $30 million dollar advantage over alternative sites. The site was the location of a previous compressor and the land is still owned by NOVA. As for noise levels caused by the compressors, NOVA stated that it would meet or exceed those requirements specified in the Board's Noise Control Directive ID 92-2. NOVA has completed a survey of ambient sound levels at the nearest residences and has committed to monitor sound levels at these residences after construction, to ensure compliance with the Board's requirements. NOVA stated that it had designed the facility with additional silencing devices and would be installing silencers in the unit vents and the station blowdown vent, to attenuate noise arising from unit start-ups and station emergency shutdowns.

5.2.2 Views of the Landowners

Mr. Ian Carver lives within 3 km of the proposed Turner Valley compressor site. His concerns were expressed in letters of 7 July and 12 December 1992 and related to the proposed location of the compressor station and the resulting noise level at his residence. He does not believe the Board's noise requirements are adequate. Mr. Carver also stated that an alternative compressor station site near Calgary might be more appropriate.

Mr. George Stovka is the owner of the northwest quarter of 3-8-5 W3M on the proposed Lundbreck Loop. His concerns, expressed in letters of 28 August and 30 November 1992, related to previous work completed on his land. Mr. Stovka had concerns regarding top soil replacement and repairs to a pond and spring on his land. He stated that NOVA agreed to restore grass growth on the right of way and to repair the spring. Mr. Stovka's letter did not identify any specific concerns related to the applied-for facilities.

Although both parties were given direct notice, neither landowner was present at the hearing.

5.2.3 Views of the Board

The Board is satisfied that the proposed facilities are technically and environmentally satisfactory. With respect to Mr. Carver's concerns, the Board accepts that the Turner Valley location for the proposed compressor station is the most economic and has limited public and environmental impact. The Board notes that NOVA will meet or exceed the Board's noise level requirements. With regard to Mr. Stovka's concerns, the Board notes he did not identify any concerns specific to the applied-for facilities. The Board expects NOVA will take reasonable steps to resolve Mr. Stovka's concerns respecting previous work on his land.

6 CONDITIONS RELATING TO THE SIZE AND TIMING OF THE FACILITIES

6.1 Views of NOVA

NOVA stated that all the applied-for facilities were required and must be constructed and placed in-service by 1 November 1993 in order to meet its 1993-94 firm service contracts. NOVA emphasized that the sequencing of construction was of paramount importance to avoid environmental constraints and significant delivery impacts at the Alberta - B.C. border. The Turner Valley compressor station is on the critical path and NOVA stated that approval of this facility, in particular, by 1 March 1993 was necessary to meet its 1 November 1993 in-service date.

NOVA stated that, if only partial approval was received, some redesign might be required since the proposed facilities represented the optimum design for the forecast flow and for outage protection. Should only partial approval be granted, NOVA testified that it would prorate the approved partial capacity based on each shipper's contracted volume against the total contracted volume.

NOVA stated that it would be prepared to take reasonable steps to co-ordinate its in-service date with downstream facilities, provided it could reach an agreement with all shippers to compensate NOVA for the accumulated allowance for funds used during construction. If a condition is attached by the Board to the permits, NOVA would not start construction until it could renegotiate its contract agreements with all the shippers. NOVA emphasized that its contract terms and conditions, which would include the imposition of a billing commencement date, would be subject to complaint to the Board under section 40 of the NOVA Act.

6.2 Views of Interveners

Most shippers argued that all the applied-for facilities should be approved expeditiously to meet the 1 November 1993 in-service date. If the facilities were downsized, it would affect the entire PGT Expansion Project causing significant uncertainty as to how the NOVA capacity would be allocated. If partial approval were granted based only on long term gas removal permits or export licence volumes, there would be no pipeline capacity available for those volumes expected to move through short term sales contracts.

PGT stated that the US portion of the PGT Expansion Project in the PNW and California is a single construction project of two years duration. Sixty-five percent of the project construction has been completed and the remaining portion will be completed before the scheduled in-service date of 1 November 1993. PGT has no intention of downsizing the project. ANG stated that it had not evaluated downsizing its project.

A number of interveners argued that the NOVA facilities could and should be downsized. Altamont stated that the Board should approve a combination of facilities that would provide capacity to accommodate only the volumes of those shippers that provided reasonable evidence that gas would flow. It believed that approximately half of the applied-for volumes would have a reasonable certainty of flowing by 1 November 1993. Altamont estimated that an incremental capacity of 450 MMcf/d would be possible on the US portion of the PGT Expansion Project, if only construction in progress was completed.

Amoco stated that only those facilities that would provide incremental capacity for long-term contracts should be approved and suggested that the approval of all applications except the Lundbreck Loop would achieve this.

A number of shippers requested that the Board condition its approval by requiring NOVA to link the in-service date of the facilities with those of the downstream PGT Expansion Project. This linkage was needed because if either the in-service date of the NOVA facilities or the remainder of the PGT Expansion Project were delayed, the shippers would incur unmitigable demand charges. Others argued that a condition was necessary because of regulatory uncertainty surrounding the PGT Expansion Project and the California market.

PGT stated that the matter of an in-service date linkage should be between NOVA and its shippers and not decided by the Board. PGT also stated that NOVA was an unaffiliated entity and therefore, it would be difficult to create a contractual relationship for linkage of in-service dates between them.

Altamont did not believe that a linkage condition was required. It believed the shippers should face the consequences of contracts they entered into freely. Chevron stated that any condition should be framed in such a way that no further negotiations between shippers and NOVA were required. Chevron suggested that the permits be conditioned to defer commencement of construction as long as possible and to proceed at a pace to be consistent with the in-service date common to other links in the PGT Expansion Project.

6.3 Views of the Board

With respect to the issue of whether all or only a portion of the facilities should be approved, the Board believes, should it find the facilities to be in the public interest, that it must at least approve a combination of applied-for facilities which would meet the long term sales contracts of approximately 400 MMcf/d. The Board also believes that there is little merit in approving only a portion of the facilities if significant incremental capacity can be added for little extra cost. The cost of the Lundbreck Loop is estimated by NOVA to be $11 million, compared to the total estimated cost of $116 million for all the facilities. The incremental capacity of all the facilities, with and without the Lundbreck Loop, is 800 MMcf/d versus 345 MMcf/d. Amoco's suggestion of approval of all applied-for facilities, except the Lundbreck Loop, would provide insufficient incremental capacity for conveying the long term contract sales. Furthermore, the option without the Lundbreck Loop would only reduce the total costs by 10 percent but would reduce the total incremental capacity by more than 50 percent. The Board does not believe this option is reasonable.

The Board notes that Chevron, which has requested 53 MMcf/d of incremental capacity from NOVA, is the only shipper that has expressed some doubts regarding how to most effectively enter the California market at this time. The other shippers have either sales contracts in hand or have expressed a strong willingness to enter the California market now on a short term basis. The Board does not believe that the cost of limiting the possibility of short term sales through restricting capacity is justified.

With respect to the matter of in-service date co-ordination with all downstream facilities, the Board notes that ANG, PGT, PG&E and NOVA have all committed to a common in-service date of 1 November 1993 and that NOVA has further committed to take reasonable steps and to negotiate with the affected parties for ensuring co-ordination. Although the Board agrees that the timing of in-service dates of all the facilities should be co-ordinated, it is not inclined to interfere with the freely negotiated terms of the agreements under which the facilities are being developed.

7 DECISION

Having considered all the evidence, and having regard for its responsibilities under the Pipeline Act, the Board has approved the six pipeline applications as applied for by NOVA, without conditions. The Board has referred the applications to the Minister of Environmental Protection pursuant to section 8 of the Pipeline Act.

DATED at Calgary, Alberta, on 7 May 1993.

ENERGY RESOURCES CONSERVATION BOARD

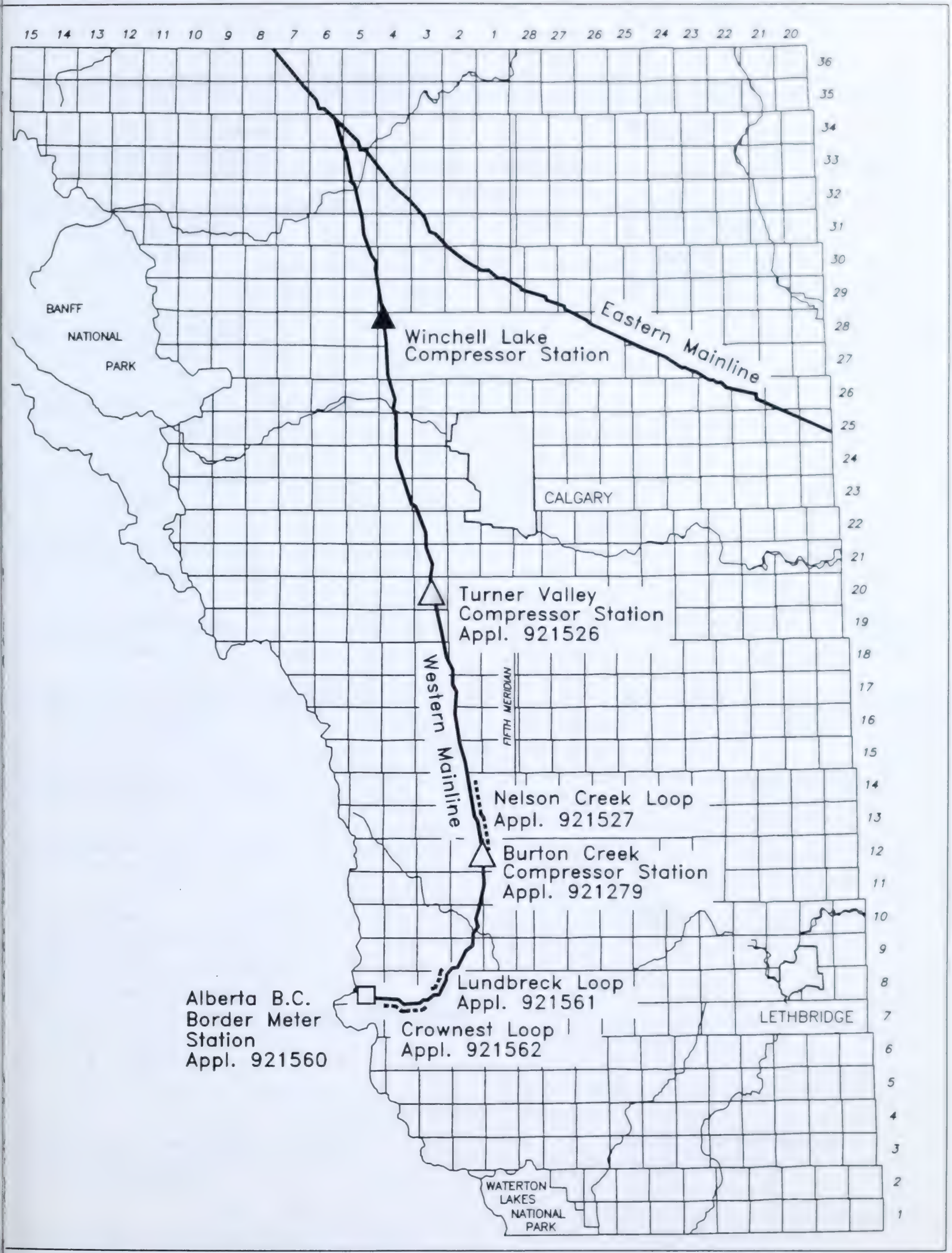
J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

F. J. Mink, P.Eng.
Vice Chairman

Bruce F. Bietz

B. F. Bietz, Ph.D.
Board Member


15 14 13 12 11 10 9 8 7 6 5 4 3 2 1 28 27 26 25 24 23 22 21 20
36 35 34 33 32 31 30 29 28 27 26 25 24 23 22 21 20 19 18 17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1
BANFF NATIONAL PARK
Winchell Lake Compressor Station
Eastern Mainline
CALGARY
Turner Valley Compressor Station Appl. 921526
Western Mainline
FIFTH MERIDIAN
Nelson Creek Loop Appl. 921527
Burton Creek Compressor Station Appl. 921279
Lundbreck Loop Appl. 921561
Alberta B.C. Border Meter Station Appl. 921560
Crownest Loop Appl. 921562
LETHBRIDGE
WATERTON LAKES NATIONAL PARK

POSED ADDITIONAL FACILITIES ON NOVA WESTERN MAINLINE

lications No. 921279, 921526, 921527,
921560, 921561, 921562

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
NOVA Corporation of Alberta (NOVA) H. D. Williamson D. R. Wright	K. Hutton, P.Eng. R. Haynes,P.Eng. R. Schmidt R. Cormier, P.Eng.
AEC Oil & Gas Company P. H. Davies	
Alberta & Southern Gas Co. Ltd. (A&S) N. W. Boutillier	
Amerada Hess Canada Ltd. R. Jones	
Brymore Energy Ltd. D. C. Edie	
CanWest Gas Supply Inc. R. Beattie	C. Coe
DeKalb Energy Canada Ltd. (DeKalb) D. R. Wright	B. A. Craig
Grand Valley Gas Company K. Miller	
IGI Resources, Inc. M. Moseley	
Joint Submittors AEC Oil & Gas Company Imperial Oil Resources (Esso) Western Gas Marketing Ltd. Southern California Edison Company (SoCal Edison) L. Keough P. H. Davis D. McLean	
Norcen Energy Resources Ltd. (Norcen) D. W. Rowbotham A. Broughton	B. MacDonald, P.Eng. B. Jackson, P.Eng.
North Canadian Oils Limited (North Canadian) D. W. Rowbotham	C. Worthy

THOSE WHO APPEARED AT THE HEARING CONTINUED

Principals and Representatives (Abbreviations Used in Report)	Witnesses
North Canadian Marketing Inc. (North Canadian) D. W. Rowbotham	C. Worthy
Pan Canadian Petroleum Limited R. Mackie	C. Johnston
Paramount Resources Ltd. R. B. Hillary	R. Duncan, P.Eng.
Petro Canada S. Miller B. Moghadam	
San Diego Gas & Electric Corp. (SDG&E) L. Smith N. Gretener	
Shell Canada Limited (Shell) E. S. Decter	D. Sutton R. Cusson
Suncor Inc. (Suncor) D. W. Rowbotham	A. Wells, P.Eng.
Unigas Corporation P. McMillan	
Vector Energy Inc. M. Brener	M. Brener, P.Eng.
Washington Energy Resources (Washington Energy) R. Epling	R. Epling B. Bierbach
Joint Sponsors Alberta Natural Gas Company Ltd. (ANG) Foothills Pipe Lines Ltd. Pacific Gas Transmission Company (PGT) Pacific Gas & Electric Company (PG&E) T. Dalgleish D. G. Hart J. Lutes	K. Peake T. Cameron P. Rosput R. Oechsler
Altamont Gas Transmission Company (Altamont) A. L. Mclarty R. A. Neufeld	B. Friedenberg P. Carpenter E. Muse M. Day

THOSE WHO APPEARED AT THE HEARING CONTINUED

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Altana Exploration Company and Roan Resources Ltd. R. A. Neufeld	
Amoco Canada Petroleum Company Ltd. (Amoco) F. M. Saville	J. R. Crawford, P.Eng. T. G. Ehinger
Chevron Canada Resources (Chevron) K. Archibald	
Czar Resources Ltd. (Czar) G. Walsh	D. Clark
Industrial Gas Consumers Association of Alberta (IGCAA) F. Martin	
ProGas Limited (ProGas) J. Kowch	
TransCanada PipeLines Limited M. Samuel	
Westcoast Energy Inc. M. Manning	
Energy Resources Conservation Board Staff M. Bruni J. Yu, P.Eng. A. Larson, P.Eng. J. Amoruso G. Habib M. Pinney L. Holizki, P.Eng. K. Fisher	

APPENDIX A

INTERIM DECISION D 93-1

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

NOVA CORPORATION OF ALBERTA (NOVA)
FOR PERMITS TO CONSTRUCT ADDITIONAL FACILITIES
TO NOVA WESTERN MAINLINE

Interim Decision D 93-1
Applications 921279, 921526,
921527, 921560, 921561, and 921562

The Board has considered NOVA's applications, and the evidence submitted at the hearing on the subject applications commencing on 12 January 1993. It is satisfied that the applied-for facilities are needed to provide incremental gas delivery capability to the Alberta-British Columbia border and in the long term interest of the province. Accordingly, the Board is prepared to issue the permits as applied-for by NOVA, without conditions, subject to receipt of the required approvals of the Minister of Environmental Protection respecting environmental matters.

A detailed report providing reasons for the Board's decision will be forthcoming.

DATED at Calgary, Alberta, on 2 March 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D.*
Vice Chairman

F. J. Mink
Vice Chairman

B. F. Bietz, Ph.D.
Board Member

---

* J. P. Prince, Ph.D. was unavailable for signature, but concurs with the contents and with the issuing of this Interim Decision.

APPENDIX B

ATTACHMENT TO IL 90-8

Attachment to Informational Letter IL 90-8

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

The Board will use the following procedures for assessing NOVA pipeline applications.

A. . . .

J. In assessing each facility application with respect to the need of notice, the Board will have regard for its review of the application and the Annual Plan, submissions received respecting the Annual Plan, concerns submitted regarding the facilities, and any significant changes in facts or circumstances between the filing of the Annual Plan and the application. If every aspect referred to above is deemed by the Board to be satisfactory, the application may be approved without a notice for objection, and if not, a notice will be issued. The notice for objections would typically be issued for an application with a capital cost in excess of $10 million.

K. In certain instances where submissions have already been filed or the Board is aware that objections will likely be filed, it may go directly to public hearing. Additionally, where valid objections are filed as a result of notice, a hearing will be held.

ERCB

Simon and Michael Skinner Amax Petroleum of Canada Inc.

Applications for Review or Development of Facilities, Wells, Spacing Order, and Holdings

Hayter Field - Provost Area

HAYTER FIELD
APPLICATION FOR REVIEW OF WELLS, OIL PRODUCTION FACILITIES AND SPACING ORDER BY SIMON AND MICHAEL SKINNER
APPLICATIONS FOR HOLDINGS, SPACING ORDER, WELLS AND OIL PRODUCTION FACILITIES BY AMAX PETROLEUM OF CANADA INC.

ERCB D 93-3

March 1993

Published by

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
T2P 3G4

Telephone (403) 297-8311

Facsimile (403) 297-7040

CONTENTS

1 INTRODUCTION . . . 1

1.1 Applications and Interventions . . . 1
1.2 The Hearing . . . 2
1.3 Background . . . 5

1.3.1 Area Description . . . 5
1.3.2 Sequence of Events Leading To The Hearing . . . 6
1.3.3 Current Status of Amax Operations . . . 7

2 SECTION 42 REVIEW OF AMAX OPERATIONS . . . 9

2.1 Introduction . . . 9
2.2 Issues . . . 9

2.2.1 Well And 10-16 Battery Operations . . . 9
2.2.1.1 Views Of The Skinners . . . 9
2.2.1.2 Views Of Amax . . . 11
2.2.1.3 Views Of The Board . . . 14

2.2.2 Dairy Farm Operating Practices . . . 15
2.2.2.1 Views Of The Skinners . . . 16
2.2.2.2 Views Of Amax . . . 17
2.2.2.3 Views Of The Board . . . 17

2.3 Environmental Impacts . . . 18

2.3.1 Atmospheric Impacts . . . 18
2.3.1.1 Views Of The Skinners . . . 18
2.3.1.2 Views Of Amax . . . 19
2.3.1.3 Views Of The Interveners . . . 22
2.3.1.4 Views Of The Board . . . 22

2.3.2 Subsurface Impacts . . . 23
2.3.2.1 Views Of The Skinners . . . 23
2.3.2.2 Views Of Amax . . . 24
2.3.2.3 Views Of The Board . . . 24

2.3.3 Surface Impacts . . . 25
2.3.3.1 Views Of The Skinners . . . 25
2.3.3.2 Views Of Amax . . . 27
2.3.3.3 Views Of The Interveners . . . 29
2.3.3.4 Views Of The Board . . . 29

2.3.4 Effects On The Dairy Herd 31
2.3.4.1 Views Of The Skinners 31
2.3.4.2 Views Of Amax 32
2.3.4.3 Views Of The Interveners 32
2.3.4.4 Views Of The Board 33

2.4 Social Impacts 35

2.4.1 Views Of The Skinners 35
2.4.2 Views Of Amax 35
2.4.3 Views Of The Board 36

2.5 Company/Landowner Communications 36

2.5.1 Views Of The Skinners 36
2.5.2 Views of Amax 37
2.5.3 Views Of The Board 37

3 APPLICATIONS BY AMAX 39

3.1 Well License Applications 39

3.1.1 Need 39
3.1.1.1 Views Of Amax 39
3.1.1.2 Views Of The Skinners 39
3.1.1.3 Views Of The Board 39

3.1.2 Location And Impact Of The Proposed Wells 39
3.1.2.1 Views Of Amax 39
3.1.2.2 Views Of The Skinners 40
3.1.2.3 Views Of The Board 41

3.2 Satellite Production Facility 42

3.2.1 Views Of Amax 42
3.2.2 Views Of The Skinners 42
3.2.3 Views Of The Board 43

3.3 Pipelines Applications 43

3.3.1 Views Of Amax 43
3.3.2 Views Of The Skinners 43
3.3.3 Views Of The Board 43

CONTENTS

3.4 Production Facilities And Holding/Spacing Application 43

3.4.1 Technical Suitability of 10-16 Battery Modifications 43
3.4.1.1 Views Of Amax 43
3.4.1.2 Views Of The Skinners 44
3.4.1.3 Views Of The Board 44

3.4.2 Proposed Expansion And Holding/Spacing Application 44
3.4.2.1 Views Of Amax 44
3.4.2.2 Views Of The Skinners 45
3.4.2.3 Views Of The Board 45

4 ACTIONS TO ADDRESS IMPACTS 48

4.1 The Skinner Proposal 48

4.1.1 Views Of The Skinners 48
4.1.2 Views Of Amax 49

4.2 Board Direction 50

5 DECISION 54

Appendix A (Exhibit 17) Measures Taken By Amax At 10-16 Battery

Appendix B (Exhibit 25) Amax Proposal For Continued Operation Of Battery And Holding Development

Appendix C Amax Operations At The 10-16 Battery

Figure 1 Hayter Field And Area Of Application

Figure 2 Surface Development Section 16-41-1W4M

Figure 3 Surface Development Skinner Proposed Setback Zones and Amax Proposed Development Section 16-41-1W4M

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION NO. 910526
SIMON AND MICHAEL SKINNER
APPLICATION FOR REVIEW OF WELLS, FACILITIES AND
SPACING ORDER

APPLICATIONS NO. 910289, 910790, 910972 AND
910890 TO 910905 INCLUSIVE
AMAX PETROLEUM OF CANADA INC.
APPLICATIONS FOR HOLDINGS, SPACING ORDER, WELLS AND FACILITIES
HAYTER FIELD

Decision D 93-3

---

1 INTRODUCTION

1.1 Applications and Interventions

Application No. 910526 was made on 4 April 1991 by Simon and Michael Skinner (the Skinners) pursuant to section 42 of the Energy Resources Conservation Act (the Act) for a review of the following Energy Resources Conservation Board (ERCB) approvals:

(a) Battery Approval No. FS04587, an oil battery located at Legal Subdivision 10 of Section 16, Township 41, Range 1, West of the 4th Meridian (the 10-16 battery);

(b) Well Licence Nos. 0036069, 0077707, 0126936, 0126937, 0126950, 0126951, 0128313, 0128314, 0128315, 0129290, 0129291, 0129293, 0130375, 0130376, 0130379, 0130430, 0130921, 0131797, 0131799, 0131802, 0131803, 0140545, 0143409, 0143799, 0144248, 0144249, 0144250, 0144251 and 0144255, that produce or are capable of producing to the 10-16 battery;

(c) All satellite production facilities that produce or are capable of producing well effluent to the 10-16 battery; and

(d) Board Order No. IW 9011.

Amax Petroleum of Canada Inc. (Amax) applied for approval of the following:

(a) Application No. 910289, pursuant to section 5.190 of the Oil and Gas Conservation Regulations (the Regulations), to establish two holdings, one comprising Section 16 and one for the Southeast quarter of Section 21, Township 41, Range 1, West of the 4th Meridian for the production of oil from the Dina Member of the Mannville Group and pursuant to section 71, subclause (4) of the Oil and Gas Conservation Act, to suspend the application of Part 4 of the Regulations and provide a special spacing order for wells drilled or to be drilled within the holdings. In the rest of this report this application is referred to as the "holding/spacing application."

(b) Application No. 910790, pursuant to section 7.001 of the Regulations, for approval to construct a satellite production facility at Quadrant D, Legal Subdivision 10 of Section 16, Township 41, Range 1, West of the 4th Meridian (the 10D-16 satellite).

(c) Application No. 910972, pursuant to Part 4 of the Pipeline Act, to construct approximately 2 kilometres (km) of 88.9 millimetre (mm) outside diameter test and production pipelines to transport oil well effluent from sixteen wells proposed to be drilled in Section 16, Township 41, Range 1, West of the 4th Meridian.

(d) Applications No. 910890 to 910905 inclusive, pursuant to section 2.020 of the Regulations, for sixteen well licences for wells to be drilled from surface locations at Legal Subdivisions 7, 10, 14, 15 and 16 of Section 16, Township 41, Range 1, West of the 4th Meridian, for the production of oil from the Dina Member of the Mannville.

An intervention opposing the Amax applications was filed by the Skinners based on the impacts the applications would have on the Skinners' dairy operation, the environment and the health of their livestock and families.

Interventions were also filed by the Alberta Cattle Commission, the Christian Farmers Federation of Alberta, and the Shell Caroline Agricultural Society.

The Alberta Environmental Centre filed a submission as an interested party in the proceeding.

1.2 The Hearing

The Board decided to consider the Amax and Skinner applications at one hearing. A public hearing of the applications was held in Provost, Alberta, and was conducted on 13 to 17 and 27 to 31 January 1992, 24 to 28 February 1992, 13 to 14 and 21 to 24 April 1992, and 4 to 6 May 1992. The hearing was held before Board Members F. J. Mink, P.Eng., B. F. Bietz, Ph.D., P.Biol., and N. G. Berndtsson, P.Eng. (the Board). A site visit to the Skinner dairy and Amax operations on Section 16 was conducted 13 January 1992, and was attended by Amax, the Skinners, the Board, Board staff and other participants at the hearing. Those who appeared at the hearing are listed on the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Amax Petroleum of Canada Inc. (Amax) P. B. Budd C. D. Johnstone	C. A. Hemstock, P.Eng. B. G. Berkan, P.Eng. W. G. Schultz G. A. Atkins, DVM J. A. Lore, P.Ag. of Jim Lore and Associates Ltd.

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Amax Petroleum of Canada Inc. (Amax) (cont'd)	G. A. Nordstrom, DVM J. K. Farries, P.Eng. of Farries Engineering (1977) Ltd. D. M. Leahey, Ph.D of Western Research A. R. Scheibner, P.Ag. of Western Oilfield Environmental Services Ltd. D. Headdon, M.Sc. of Western Oilfield Environmental Services Ltd. R. Clissold, P.Geol. of Hydrogeological Consultants Ltd.
Skinner Bros. Dairy Farms Ltd. (Skinners) D. B. Roth J. P. Kudrinko	M. Skinner S. Skinner J. Skinner C. Skinner W. Wong, C.E.T. of Entech Environmental Services Ltd. D. Mancuso, P.Eng. of Enex Engineering Ltd. J. A. McCarthy of S.E.M. Consultants Ltd. A. J. Webb of S.E.M. Consultants Ltd. K. U. Weyer, Ph.D. of W.D.A. Consultants Ltd. M. Genest, Ph.D. of Clinical and Consulting Psychological Services B. Beck, DVM of Alberta Agriculture J. Ferguson, DVM of Western College of Veterinary Medicine

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Skinner Bros. Dairy Farms Ltd. (Skinners) (cont'd)	J. Wasmuth of Galigan MacAllister Associates Inc. S. H. Poulsen, DVM of Wainwright Veterinary Clinic (1990) Ltd. M. Zelensky, P.Eng., of Concord Environmental R. Corbett, M.Sc. of Alberta Agriculture
Alberta Environmental Centre	R. W. Coppock, DVM M. S. Mostrom, DVM D. H. McNabb R. Coleman, Ph.D.
Alberta Cattle Commission	T. Livingston D. Overguard
Christian Farmers Federation of Alberta	H. Bulten
Shell Caroline Agricultural Society	D. Jones
N. Taylor	N. Taylor
W. E. Bocock	W. E. Bocock
Energy Resources Conservation Board Staff C. S. Richardson, C.E.T. R. D. Heggie, Counsel L. A. Schmidt, C.E.T. B. B. Boyd I. T. Weleschuk, P.Ag. J. J. Kennelly, Ph.D., P.Ag. H. B. Schiefer, DVM, Ph.D.	

1.3 Background

1.3.1 Area Description

The area of application is in the Hayter Field which is defined by Board Order F 6123 (Figure 1). The Field comprises 79 sections of land in Townships 40 and 41, Range 1, W4M. Oil production is primarily from the Dina Member of the Mannville Group (Dina) and contains small amounts of hydrogen sulphide (H_2S). There is also some oil production from the Sparky Member of the Mannville Group (Sparky).

The Dina typically occurs as a stream deposited sandstone that overlies the erosional surface of older Devonian age carbonate rock. The sandstone has high permeability and porosity and the reservoir pressure within the sandstone is supported by a strong water drive. Water will migrate to a wellbore from below the oil zone and create an effect referred to as water coning. Well drainage areas are limited due to the water coning problem and as a consequence, close spacing between wells is required to recover the reserves. As a result of these fluid and reservoir characteristics, some Dina pools in the Hayter Field have special drilling spacing units (DSU's) which result in a high well density. Similar well densities are prevalent in the Dina pools in the larger Provost Field which lies to the south of the Hayter Field.

The Dina A Pool in the Hayter Field was discovered in 1954, although full development of the pool did not commence until the mid 1980s. In 1987, the pool was placed on Good Production Practice (GPP) which allowed for increased production rates subject to good reservoir management. The pool area consists of approximately 1400 hectares (ha) and the portion of the pool subject to the holding/spacing application proposed by Amax is Section 16 and the South-east quarter of Section 21-41-1 W4M (the SE of 21). The first well drilled in the area of application was located at Lsd 10-16-41-1 W4M. Pool development in the area initially proceeded on 64 ha DSU's until 1987 when 4 ha DSU's with central target areas were approved for Section 16. In 1988, 4 ha DSU's were approved for the drilling of Dina oil wells in the SE of 21 and in 1990, an infill well order (Order No. IW 9011) was approved for Lsd 10 of Section 16. This order was in response to a spacing application by Ladd Exploration Company (Ladd) to provide for the drilling of 2 wells, one of which would be a horizontal well. The order provided for a minimum subsurface interwell spacing of 75 metres (m) between wells producing from the same pool in Lsd 10 of Section 16.

Construction of the 10-16 battery was completed in 1987. Twenty-nine Dina oil wells produce to the 10-16 battery, 26 of which are located in Section 16. Satellite facilities produce well fluids via pipelines to the 10-16 battery from locations at 4-16-41-1 W4M, 10-16-41-1 W4M, and 16-16-41-1 W4M.

Sparky oil development since the late 1960s through to the late 1970s has also resulted in a considerable number of wells, pipelines and an oil battery in Section 16. A Sparky oil production battery located at Lsd 8-16-41-1 W4M (the Sparky battery) was built in 1968, and modified over the years to accept production from new wells. Until 1987 the Sparky battery also accepted production from Dina wells. The Sparky battery currently receives production from 26 wells, 11 of which are located in Section 16.

Concurrent with oil and gas development on Section 16 has been the development of the Skinner dairy farm. The Skinner family dairy has operated since 1967, when Mr. John Skinner, father of Messrs. Simon and Michael Skinner, expanded the farm operations to start commercial milk production. In

1976, Simon and Michael took over operation of the farm from John Skinner and have since expanded the operation. In 1981, a 120-head capacity milking barn was constructed and the Skinners commenced a more intensive breeding program to improve the genetic pool within the herd. The genetic improvements have continued to the present and the herd currently consists of about 260 head of cows, heifers and calves. In 1986, the Skinners undertook several construction projects on the farm that included the building of a new calf barn, new corrals, the construction of a new house, additions to another house and the drilling of a new water well. In 1987 another water well was drilled, bringing the total number of farm water wells to seven. In addition to the dairy, the Skinners cultivate approximately 1200 ha of land for grain production.

The Skinner farmstead is located in the north-half of Section 16, in what has been described as a topographic bowl (the Skinner bowl) set within regionally elevated low rolling hills (Figure 2). The ground elevations in the vicinity of the farm range from approximately 740 to 770 m above sea level, and the mean elevation of the Section is from 50 to 100 m higher than the regional topography. The Skinner bowl is enclosed on the north, west and south by higher land and is open to the east with a narrower coulee running out to the north-west. A permanent slough is located on the east side of the farm and is used for watering livestock in the summer. The low rolling topography and the local climate create a parkland environment of poplar trees and grassy knolls. Much of Section 16 has been cultivated for crop production. Surrounding much of the Skinner bowl are oil wells, pipeline right-of-ways and production facilities. The 10-16 battery is located on a low hill approximately 200 m south and 20 m above the farmyard.

The Skinner farm is home to 18 individuals, comprised of four families living in four residences. John and Pat Skinner and the family of Blaine Skinner both reside on the North-west corner of Section 16. These two residences, located on higher ground and approximately 800 m north-west of the 10-16 battery, are farthest from the dairy operation and Section 16 oilfield activity. The family of Michael Skinner reside on the west side of the Skinner bowl in Lsd 13-16 approximately 700 m north-west of the 10-16 battery. The family of Simon Skinner reside lower in the Skinner bowl in Lsd 15 approximately 350 m north of the 10-16 battery. The 10-16 battery is within 250 m of the milking barn. The milking barn is the main area of daily work activity for the Skinner family.

The Skinners rely on groundwater to supply the four families resident on the farm, as well as for their dairy operation. Of the seven water wells in or near the Skinner farmsite, four are currently in use and tied into the water system used to supply water for the dairy. The three unused wells have "sanded in" and can no longer be pumped. All seven wells appear to be completed in the Grizzly Bear shale at a depth of between 110 to 130 m from surface. The wells appear to be completed into unconsolidated surficial material, although they may be in or near the bedrock; driller's logs for the wells are inconclusive. The low sodium levels and other water quality parameters indicate that the primary source of water in the wells is surficial aquifers.

1.3.2 Sequence Of Events Leading To The Hearing

Over the years that the Sparky and Dina oil pools have been developed, the Skinners and Ladd (predecessor to Amax) established a working relationship that allowed concurrent development of both industries. Prior to 1987 the production tended to be largely from Sparky oil operations with limited environmental and social impact.

The Skinners based their request for a review on the impacts they believed had resulted from the Ladd operations involving the production of sour crude oil from the Dina. Those impacts were described as ongoing odours and possible health impacts due to emissions from the batteries, wells and facilities; the effects of H_2S and sulphur dioxide (SO_2) emissions from the 10-16 battery on the Skinner dairy herd; contamination of land and water from oil sprays and oil and salt-water spills; health and safety hazards from a field fire caused by operational upsets at the 10-16 battery; and from noise, dust, increased traffic and other sources of stress. In the request for a review the Skinners stated that they had little knowledge of the rights of a landowner during their prior working relationship with Ladd and were unaware of potential impacts from oilfield activities in proximity to a farm.

Prior to the current applications, Ladd applied in September 1990 for an amendment of Approval No. 32027 for the construction of two pipelines from a four well pad located in Lsd 10 of Section 16 to a field satellite facility located in the same Lsd. The Skinners, at that time, requested the Board review the licences for the four wells located in Lsd 10 of Section 16, in accordance with section 42 of the Act. A public hearing was scheduled to consider the pipeline applications and a review of the four well licences. Prior to the hearing Ladd and the Skinners entered into an agreement regarding the proposed pipelines and four wells which resulted in withdrawal of the request for review. This allowed Ladd to produce the four wells to the 10-16 battery and the hearing was cancelled.

Also prior to the submission of the current applications before the Board, Ladd applied and subsequently withdrew three well licence applications and an initial holding/spacing application. This holding/spacing application was for the production of oil from the Dina for Section 16 and would have allowed for a subsurface interwell distance of 75 m and a buffer zone of 50 m to the sides of Section 16. Ladd identified 57 potential infill well locations within Section 16. The Skinners withdrew their earlier support for the initial holding/spacing application based on their belief that they were misinformed about the extent of Ladd's development plans. Ladd decided that it would withdraw the applications and prepare a comprehensive development plan that would more effectively address the Skinners' concerns and provide a directional plan for its operations on Section 16. The holding/spacing application and well licence applications currently before the Board represent Amax's comprehensive plan for the development of the Dina A Pool in Section 16.

The Board considers the applications before it to represent a very unusual situation. The type and scale of development of the two industries, that is intense oil and agricultural development, coupled with their proximity, is uncommon and relatively unique in the Board's experience. The Board retained a veterinary toxicologist and dairy production consultant to assist Board staff in the review of the submissions and in cross examination at the hearing.

1.3.3 Current Status Of Amax Operations

Within Section 16 there has been no new oil and gas development since early 1991 but Amax has monitored and improved its existing wells and facilities as required. Amax conducted an air monitoring program in 1991 to identify sources of H_2S and SO_2. The program revealed the 10-16 battery (Dina production) and certain well heads as sources of H_2S and changes were made to the battery and wells to correct the emission problems. A continuous air monitoring unit has been on location between the 10-16 battery and the Skinner dairy barn since 1990. This has allowed Amax to identify the times and directions from which H_2S emissions may occur and resulted in modifications to the 10-16 battery to reduce fugitive odours and emissions. These modifications are discussed in more detail in

Section 2.2.1. With respect to the existing wells on Section 16, all producing wells are powered by electric screw pumps and the surplus portions of the surface leases are returned to agricultural use. Some of the locations are fenced to prevent unauthorized access or access by cattle. There is no trucking of fluids from the wells as all wells are produced by pipeline to either the 10-16 or the Sparky battery.

2 SECTION 42 REVIEW OF AMAX OPERATIONS

2.1 Introduction

The Skinners requested that the Board review the existing Amax operations and spacing order pursuant to section 42 of the Act. Section 42 states that "The Board may review, rescind, change, alter or vary an order or direction made by it, or may rehear an application before deciding it." The Board is of the view that section 42 requires the consideration of two questions. The first is whether the Board should review the existing licences and approvals. The Skinners questioned the reliability and safety of the Amax facilities and its operations. They submitted that the intensity of the development, coupled with its proximity to the Skinners' dairy and residences, greatly increased the risk of adverse impact upon the farm, particularly if the facility was poorly designed or operated. The Board determined that it should review the existing licences and approvals and called for that review in the Notice of Hearing. The second question, to be determined by the Board in this report, is whether the existing Amax licences and approvals should be rescinded, changed, altered or varied.

2.2 Issues

The Board believes the issues to be addressed in the section 42 review are:

- general Amax well and battery operations,
- dairy farm operating practices,
- environmental impacts, including:
    - atmospheric impacts
    - subsurface impacts
    - surface impacts
- effects on the dairy herd,
- social impacts, and
- company/landowner communications.

2.2.1 Well And 10-16 Battery Operations

2.2.1.1 Views Of The Skinners

The Skinners submitted that several factors related to the Amax operations create undue risk to the livelihood of the Skinner families, their personal health, and the health of their livestock. Because of the concentration and proximity of oilfield development, particularly the 10-16 battery, to their dairy operation, the Skinners argued that the impacts and risks in this case are far greater than that normally associated with similar oilfield operations. They described past experiences with fires from the 10-16 and Sparky batteries; crop damage from oil sprays; frequent odours, particularly during winter months; concerns about the potential for surface water pollutants from the Amax facilities; numerous salt-water spills caused by underground tank and pipeline ruptures; and the stress on the Skinners and their dairy herd caused by the Amax operations.

The Skinners stated they were concerned about the effects that drilling and completion operations were having on their freshwater aquifers. The Skinners perceived contamination of aquifers during drilling operations as a real threat. They noted, contrary to Amax's assertion of using fresh water as a drilling fluid, that Amax had on several occasions used a diesel invert drilling system to solve well control problems at a depth equivalent to their domestic water wells. The Skinners said the amount of surface casing previously run by Amax was insufficient to adequately protect the aquifers from which they were obtaining their water. Their deepest water well was approximately 130 m and they noted Amax was setting only 90 to 95 m of surface casing. The Skinners submitted that surface casing should be set at least to the Grizzly Bear Shale or preferably 25 m below the Ribstone Creek Sandstone, at a depth of approximately 260 m. Witnesses for the Skinners disagreed with Amax that cementing the production string full length provided adequate protection of the aquifers below the surface casing down to the Ribstone Creek. Further, they noted cementing is difficult and there is a lack of requirements to verify the quality of the cement job. They argued that simply observing cement returns at surface is inadequate. They believed the cement may slump or it may channel up the wellbore-casing annulus creating flow paths for water from the aquifer down the wellbore. The Skinners noted the majority of wells drilled in Section 16 did not have cement bond logs to verify the integrity of the production casing cement job. Existing bond logs showed to some degree poor cement jobs and potential flow paths for water into deeper formations.

The Skinners' witnesses acknowledged the primary purpose of surface casing is for well control but also argued that protection of freshwater aquifers should be considered when determining appropriate surface casing setting depths. They argued that in order to provide adequate protection, surface casing must be set below the aquifer. They added that the casing must be cemented to surface and the appropriate cement bond or evaluation logs administered to verify the cement job integrity.

The Skinners also expressed concern with the abandonment procedures used by Amax. They submitted that with time, corrosion of the production casing string may be a problem and, if serious enough, may cause holes in the casing and communication between the wellbore and aquifers. The Skinners stated that the wellbore should be plugged with cement from total depth to surface.

The Skinners expressed concerns with respect to the design and operation of the 10-16 battery. In particular, they argued that the vapour recovery unit (VRU) is not properly controlled and may lack capacity to meet production requirements. They stated that this lack of control or capacity may have caused some of the strong odours which they have experienced in the past. The Skinners argued there is a risk of damage during cold weather conditions to the plastic suction lines leading to the VRU and if produced gas is used for line heater fuel there is a risk of fugitive emissions created by the lack of a flame shut-down system on the line heater. The Skinners submitted that the drain lines from the VRU suction scrubber discharged onto the ground outside of the VRU building and that this is a potential source of odours and groundwater contaminants. They believed the ongoing problems with odours at the 10-16 battery would be exacerbated with additional production from more wells.

The Skinners had a particular concern about fires caused by the Amax operation. Over the last 14 years at least six fires have been caused by either the Sparky or the 10-16 batteries. This included a 30-acre fire in a stubble field in 1989, some 270 m from the dairy barn, caused by the 10-16 battery. The Skinners submitted that more recently the flare went out at the 10-16 battery and oil spewed out of the stack, affecting some 23 acres of crop land. They stated that had the wind been blowing from the battery towards the dairy, there is no doubt that their cows, pasture and dairy barn would have been covered in oil. The Skinners stated the Sparky battery has a history of catching or causing fire. They contended that Amax does not have any effective equipment or an emergency plan to deal with a fire at the batteries, well sites or satellite facilities.

With respect to noise impacts, the Skinners submitted that what was once a quiet farmstead is now subject to the sounds of vehicle traffic, pumps, service rigs and drilling rigs. The sounds vary in pitch and intensity and they believed this causes increased stress in the herd. They conceded the 10-16 battery is not usually a major source of noise.

The Skinners contended the numerous pipeline breaks, fluid, oil and chemical spills, and the involuntary shut-down of some of the facilities has caused soil contamination. They stated that, given the local topography, the slough used to water livestock serves as a collection point for runoff within the Skinner bowl and thus receives any pollutants from various Amax facilities. They added that the remote sump used by Amax to contain drilling fluids is located near a spring that feeds a second livestock watering and fish pond. They were concerned that any contaminants in the runoff water would affect the health of the herd in the long term and should be considered a real risk to herd health.

The Skinners stated that prior to the relocation of the original main access road, the constant vehicle traffic caused the air to be contaminated with dust which detracted from outside activities, dirtied clothing and infiltrated the houses and buildings. The dust also became an irritant to the dairy herd. The Skinners agreed that since the relocation of the road, the dust problem had lessened considerably. However, they maintained that dust continues to be a problem during drilling and servicing operations.

The Skinners acknowledged that Amax had made some effort since 1990 to try and reduce emissions and minimize visual and noise impacts; however, they said that in the past Amax took a reactive approach to its operations and would only address a problem if the Skinners complained. Amax had not implemented effective approaches to addressing problems before they occur. As an example, they noted that when Amax added additional fire equipment to the 10-16 battery the operating staff were not trained to use the equipment. The Skinners contended that the risks caused by the present Amax operations cannot be permitted to continue nor can Amax be permitted to expand its operations since this would result in new sources of fugitive emissions, fires, explosions, noise, safety hazards and other impacts.

2.2.1.2 Views Of Amax

Amax submitted that it had drilling programs for the Dina in each of the years 1986, 1987 and 1988, with the majority of the wells being drilled in 1987. A total of 22 wells were drilled on Section 16 during this period. During drilling, generally only one rig was used and the rig would remain on Section 16 for the duration of the drilling program or portion of the program for which it was contracted. The drilling programs provided for a combination of straight and deviated wellbores having a depth of approximately 850 m. Amax said the wells were drilled with fresh water to a depth of approximately 600 m at which point the drilling contractor would change to a standard gel-chem mud system. It noted that no lost circulation or well control problems had been experienced. Amax stated that drilling records confirm that invert drilling mud was used in drilling four wells, the most recent use being the drilling at the 10-16 pad location.

Amax said that prior to drilling the well, the surface casing design and projected setting depth are determined in accordance with the Oil and Gas Conservation Regulations. Surface casing is set at approximately 90 to 95 m (10 per cent of total depth) and is cemented full length to surface. Amax noted the Hayter Dina A Pool was initially drilled prior to 1981 and consequently qualifies for an exemption from running deeper surface casing. Amax volunteered to extend the surface casing at new Dina wells to a depth of 130 m.

Amax stated that production casing is run to total depth and is cemented full length to surface. To obtain a good cement job on the production casing, centralizers are placed along its length to ensure the casing is properly centred in the hole. During the placement of the cement, the production casing is sometimes rotated or reciprocated to reduce the potential of channelling in the cement. In addition, fluids displaced to surface during the cementing job are monitored to confirm that cement returns are obtained and maintained at surface. Once cement returns are maintained at surface it is concluded that the production casing is adequately cemented and all formations are isolated behind the casing. If cement returns are not maintained, a cement bond or cement top locating log is run in the wellbore to the top of the cement and to determine whether there are exposed formations or aquifers. The appropriate ERCB Area Office is contacted to determine the need for a remedial cement job to isolate any open formation or aquifers.

Amax indicated it prefers to not do any remedial cementing unless required, favouring instead to monitor the well during its productive life and then do remedial cementing at the point of abandonment. This approach avoids perforating the casing and eliminates the potential for communication between the wellbore and outside formations through the perforations. Amax confirmed that as long as cement returns are maintained at surface, cement bond logs are not routinely run unless requested by the ERCB. Also, cement bond logs are typically not run on the surface casing. Amax said the purpose of the surface casing is predominately for well control and that the cementing of the production casing provides for adequate protection for the freshwater aquifers.

With respect to well abandonment, Amax said that it had not abandoned many wells in Section 16, but its procedure would continue to be to set a plug above the perforations and pressure test to confirm the plug is holding. The wellbore would be then filled with corrosion inhibited freshwater, a second plug placed at surface, the casing cut-off one meter below ground level and a steel cap welded in place.

Amax stated that it was converting all of the Dina wells in Section 16 to electrically-driven, progressive cavity screw pumps. With this conversion it would soon have all of the noisier hydraulic-powered units removed from service. All the wells are equipped with high pressure emergency shut-down switches. The production from the wells is flow-lined either through satellite test facilities or directly to the 10-16 battery. It contended that the only potential source of H_2S emissions from the wells would be the stuffing box that seals the pump rod. If properly maintained, leaks would be relatively rare and to date this has not been a problem at the wells.

Amax submitted that it drilled its Section 16 wells from multiple well pad locations as opposed to single well locations because this reduces surface impacts. Pad drilling requires less land for drilling and production operations, allows for fewer access roads and pipeline right-of-ways and ultimately less area will have to be reclaimed. It stated that it has endeavoured to keep well locations clean and to reclaim any oil or salt-water spill areas. It submitted that it had relocated its main access road to the wells and batteries in order to reduce vehicle activity at the Skinner farm. Amax submitted its proposal for the continued operation of the wells, the battery and the additional wells would allow the two industries to coexist and co-develop with minimal impact on each other. That proposal is discussed in greater detail in Section 4 of the report.

Amax stated it operates three satellite test facilities on Section 16 for Dina oil production. Each satellite has a production manifold that allows for production from individual wells to be diverted from the group production flowline to the test separation facilities at the satellite. This provides for measurement of oil, gas and water from each of the wells. It submitted that each satellite test separator is equipped with high and low pressure and high level shut-down switches that will shut the separator down in the event of a satellite upset. The separators are also equipped with pressure relief valves that are connected to tankage. The pressure settings of the relief valves are set higher than the shut-down settings on the separators and the wells. This prevents high pressure from the separators and wells from opening the relief valves to the tanks and emitting fluids or fugitive odours. Amax submitted there has been no instance of the relief valves opening at the satellite facilities.

Amax described the main components of the 10-16 battery to be the free-water knockout, the line heater, treater, two test separators, oil storage facilities and a VRU. It submitted that the 10-16 battery was designed with good engineering principals and with consideration for the environment, health and safety of people, and livestock in the area.

Amax said that due to numerous H_2S and SO_2 emissions from its 10-16 battery since 1987, it chose to conduct a facility review of the battery and to implement measures to minimize or eliminate the emission problem. This included significant changes to improve the storage tank VRU and the battery. These measures are detailed in Appendix A.

Amax proposed a 24-point plan for the continued operation of the 10-16 battery and the additional well developments. These points are listed in Appendix B of the report.

Amax further described in some detail its facilities and operations at the 10-16 battery. These are summarized in Appendix C of the report.

Amax submitted that although the 10-16 battery is fully equipped with sensing devices, some of which include detection and shut-down systems, the key to continued safe and successful operation of the 10-16 battery is a rigorous maintenance schedule and conscientious operating. It stated that the operation of the 10-16 battery, test satellites and wells is conducted by at least two persons on a daily basis and it has in place a comprehensive check list and maintenance program. It further submitted that the design of the facilities incorporates all practical measures to reduce or eliminate emissions and this together with its checklist and maintenance program goes well beyond normal industry practice and exceeds many of the requirements of the Oil and Gas Conservation Act and Regulations.

Amax acknowledged the Skinners' concerns with respect to odours, fire, traffic, emissions and contamination of groundwater that may result from the 10-16 battery. It stated that in the past it responded to the concerns by modifying portions of the 10-16 battery that caused the problems. It listed those measures to address the Skinners' concerns (Appendix A) and believed that they were adequate and appropriate to correct the problems.

2.2.1.3 Views Of The Board

The Board has considered the drilling and completion practices of Ladd and Amax on the wells they have drilled to date on Section 16. The Board is of the view that drilling procedures, surface casing setting depths and cementing programs were carried out by Ladd and Amax in a manner consistent with the applicable regulatory guidelines. The Board does not believe there is a measurable risk of contamination of aquifers on Section 16 because of the required surface casing setting depth for the wells. The Board agrees with Amax that the primary purpose of surface casing is for well control during the drilling of the well, and that the full length cementing of production casing will adequately protect local subsurface aquifers. The Board is not convinced by the opinions of the witnesses for the Skinners that uncemented channels down the wellbore around the production casing serve as significant conduits for groundwater flow from shallow to deeper aquifers. Notwithstanding, given the intensity of drilling in this area it may be prudent to extend the surface casing below deeper freshwater aquifers as a supplementary measure of precaution. The Board believes the current practice of cementing the entire production casing is generally adequate protection against contamination of aquifers; however, it would accept Amax's proposal to set surface casing to a depth of 130 m as an extra precautionary measure.

The Board believes that well cementing operations, if well planned and executed, will ensure isolation and coverage of all zones of concern. The Board is satisfied that monitoring cement returns during pumping operations is a suitable indicator of the success of the cementing operations. If complete cement returns are not obtained, indicating the occurrence of lost circulation while displacing cement, or if the cement level slumps back down the hole after completing pumping operations, the Board requires remedial measures be taken. These measures are based on an assessment of the cement job which very often includes a cement bond log, or temperature profile survey to determine presence or non-presence of cement. While the Board often requests bond logs in such assessments, the Board does not believe that bond logs should be a routine requirement for wells in Section 16, as suggested by witnesses for the Skinners.

The Board acknowledges the concern expressed by the Skinners on cased hole abandonment procedures used by Amax. Plugging or isolating the producing section of a cased wellbore with cement, displacing the cased wellbore to inhibited water and capping the well below ground level with a welded steel plate or cement is standard, acceptable abandonment procedure and meets present Board requirements. This has been the requirement for many years. The Board is satisfied that the well abandonment procedures proposed by Amax meet the present requirements and does not believe corrosion represents a material risk of contamination of freshwater aquifers.

The Board is concerned with regard to the extent of usage by Amax of invert (diesel-based) drilling muds. The Board would normally expect, particularly given the sensitivity of the dairy farm to both surface and subsurface contamination of water supplies, that such invert muds would be used rarely, if ever, and further that much closer, hands-on supervision of contractors during the use of invert muds would be carried out by the company. The Board will require Amax to provide the Skinners and the ERCB Wainwright area office with the details of any invert mud systems it would propose to use in future drilling operations on Section 16 prior to the commencement of drilling.

With regard to past day-to-day well site maintenance, the Board is of the opinion that, based in part on the conditions observed during the site visit, general housekeeping has likely been minimal at many well sites. The Board expects all operators to maintain their well sites in good condition, with adequate fencing, proper weed control, and minimal waste materials left on site. Even more diligent attention would be expected at any operation where the potential for conflict between the oil and gas industry and the agricultural industry is high. The Board saw little evidence that such standards had been met in the past at the Amax operations in Section 16. The Board has a similar concern with the past operation and maintenance of the central sump for drilling fluids.

With respect to past operating practices, the Board is of the view that Amax did not consistently operate its wells, gathering and testing systems, or the batteries located within Section 16 in accordance with acceptable standards. While the Board concurs with the view of the Skinners that significant improvements appear to have been made in operations, these do not appear to have been made in a proactive manner, but rather only after significant negative impacts, including odours, spills, fires, dust, and noise have occurred. It is the Board's view that the deterioration in the relationship between the company and the landowners over the past four years is a direct result of inaction by the company as well as its insensitivity to the incremental effects of ever-increasing levels of activity on both the Skinner quality of life and on their farming operations. For example, the delay in the decision to relocate the access road away from the family farm until after a significant increase in drilling activity had occurred clearly demonstrates a tremendous insensitivity to the potential impact of intensive oil and gas activity on rural lifestyles.

At the hearing, Amax made a number of commitments with regard to ongoing improvements in its operating practices. The Board accepts that improvements already made by Amax have significantly reduced impacts on the Skinners, and accepts that the proposals for future action, if carried out, should result in further improvements. The Board does continue to have concerns with some aspects of the 10-16 battery and its operation. These include:

- the proximity of the battery to an intense agricultural operation in the Skinners' farmyard, particularly since the battery and the dairy both operate 24 hours per day,
- the continued potential for fire, atmospheric emissions and liquid spills from the battery,
- the nuisance and visual impact of the flare on the Skinners, and
- the impact to surface waters and soil resulting from contamination from the battery and associated activities.

2.2.2 Dairy Farm Operating Practices

In assessing the potential impacts of the Amax oil operations on the Skinner dairy operations the Board believes it is also necessary to recognize and consider dairy management practices in general as well as the actual Skinner operation. The Board heard considerable evidence from witnesses for both sides to the effect that modern dairy operations are complex, requiring a high level of management, and are subject to a number of normal operational upsets routinely associated with intensive agricultural operations. To adequately appreciate the potential impacts of the Amax oil operations on the Skinner dairy operations, it is necessary that the Board be able to appreciate the degree of normal variability which could occur in a dairy operation (e.g. in milk production, herd health, etc.) in the absence of nearby oil and gas operations.

2.2.2.1 Views Of The Skinners

The Skinners are convinced that the Amax operation affected the health of their dairy herd and resulted in a reduction in milk production. The Skinners submitted they have been on an owner-sampler Dairy Herd Improvement (DHI) Program from 1980 to 1987. In March 1987, they became involved in the supervised DHI Program. The difference between the two programs is that under the latter program, a DHI technician collects the data rather than the dairyman. It was the Skinners' contention that data collected under both programs were equally valid and reflective of the milk production of their herd.

The Skinners attempted to maintain a "closed" herd in that they tried to produce all their own replacement cows to improve the genetic quality of the herd. They have been quite successful, especially in maintaining a very low calf mortality rate which results in the high availability of replacement heifers for their herd. Only between November of 1988 and January 1989 was it necessary to purchase replacement milk cows in order for the herd to keep milk production at the quota level required. The Skinners submitted evidence that the need to purchase replacement cows was in response to emissions from the 10-16 battery which had affected the milk production of their herd.

The Skinners stated that they did all their own herd health, artificial insemination and pregnancy examinations on their cows. They consult with local veterinarians as necessary. They believed that their training and experience allowed them to perform these tasks very successfully. They contended that it was not necessary to have a veterinarian provide a formal herd health service due to their constant contact with the animals and thus their ability to respond in a timely fashion to any observed health problems.

The Skinners produce all their own cereal grain and cereal silage used for feed and believed that their feeding program provides for proper nutrition of their dairy animals. They stated that alfalfa pellets are purchased off-farm. The feeding program has remained virtually unchanged except for the introduction of canola meal as a protein supplement in 1988, and the addition of anhydrous ammonia to the silage in 1985. Feed is sampled annually and analyzed by Alberta Agriculture Soil and Feed Testing Laboratory. Nutritional consultation is also provided by Alberta Agriculture and its recommendations are followed by the Skinners in formulating the various feed rations.

The Skinners noted that while the Amax oilfield operations virtually surround the dairy operation, the normal operations of the dairy have not been impaired by the physical location of Amax facilities except for a well site containing four directionally drilled wells located in an area previously used by the Skinners as a calf pasture (Figure 2). The Skinners stated that the site could no longer be used as pasture because it was unsafe, citing poor fencing and inadequately installed or maintained cattle-guards around the wellhead pumping mechanisms.

The Skinners stated that the milking barn utilizes a slurry manure system. The barn floor is scraped twice daily with a skid loader. The manure is pumped into a lagoon located just north-east of the barn and the lagoon is typically emptied annually, usually in the spring, onto the cultivated lands near the yard. The remaining facilities utilize a solid manure system whereby either a pack of manure and straw is built-up over the winter or in the case of the calf barn, the solid manure is removed daily from the barn onto a pile. The solid manure is also spread onto the surrounding cultivated fields. The only time that odours are detected from the manure is during the one or two days a year during which the liquid manure lagoon is being emptied. They submitted that the manure lagoon did not emit H_2S except while being emptied and then only at very low concentrations.

2.2.2.2 Views Of Amax

Amax acknowledged that the Skinners' farming operations were generally well managed and that their record keeping contributed to the Skinners' management capability. It questioned, however whether the health problems of the herd could be attributed to the oil field activity.

Amax contended that for the purposes of the hearing, only the milk production data accumulated under the supervised DHI program should be used. This independent DHI data could be verified for accuracy and consistency.

Amax acknowledged that the Skinners were very successful in raising their calves. The very low calf mortality was attributed both to the management abilities of the Skinners and the "state-of-the-art" calf barn.

Amax contended that, since the Skinners did not utilize a formal herd health program under the regular and direct supervision of a veterinarian, the herd health data and interpretations presented by the Skinners were open to question. Amax acknowledged that while herd health, including artificial insemination and pregnancy checks, was being adequately monitored by the Skinners, the Skinners did not have the appropriate background to adequately diagnose or respond to non-routine herd health concerns. Amax stated that the health symptoms observed were not specific. Since a veterinarian was involved infrequently in the herd health problems experienced by the Skinners, key information or analyses did not exist.

Amax argued that the farming operation also had an impact on the environment of the Skinner bowl. They suggested that the lagoon holding manure from the milking barn, and located in the farmyard, could contribute to H_2S concentrations and therefore odours in the farmyard.

Amax also questioned the Skinners' management of the nutritional content of their feeds. They noted that the nutritional recommendation provided to the Skinners by Alberta Agriculture was based upon very few actual feed samples. Thus, the recommendations were based upon area averages for feed quality. Such an approach would not recognize the normal annual variability in feed quality or the change in feed quality over the year.

2.2.2.3 Views Of The Board

The Board notes that all parties agree that the Skinner dairy operations are well run and managed and it concurs with this view. With regard to the Owner-Sampler DHI data provided by the Skinners, the Board accepts the Skinners' argument that their data should be as reliable as supervised DHI data. The Board is also willing to accept the data provided by the Skinners with regard to general health of their herd and pregnancy rates.

The issue of H_2S sources from the dairy operations is addressed in Section 2.3.1.4.

2.3 Environmental Impacts

2.3.1 Atmospheric Impacts

2.3.1.1 Views Of The Skinners

The Skinners contended that emissions from the 10-16 battery were having an adverse effect on their herd health and may represent a health risk to the families. The Skinners did not believe that Amax's air quality monitoring program was particularly effective or provided an accurate evaluation of the air quality in the Skinner bowl. They contended that the frequency and level of H_2S emissions have been greater in the past than was recorded by the Amax air monitoring units. They noted the role wind direction plays, since the monitor will record an emission only if it is downwind from the source. Further, the averaging of the emissions over time fails to recognize the high concentrations that may exist for short durations at any given time. They stated some of the monitored hourly average emissions exceeded the permissible ambient levels established by the Province[1]. Both the exceedances and the peak levels of emissions caused concern for their effects on the Skinner families and the dairy herd.

The Skinners submitted that during the period of 1 - 2 August 1991, they conducted a testing program at the 10-16 battery to measure and identify potential sources of odours in the ambient air. Samples were taken from the flare stack, treater stacks and one of the produced water tanks.

Analysis of samples taken from the flare tip showed only reduced sulphur with H_2S, carbonyl sulphide (COS), and carbon disulphide (CS_2) detected. Analysis of the gas collected from the downwash of the flame did not show any reduced sulphur. Analysis of the inlet gas to the flare showed the H_2S concentration varied from 1.8 to 3.2 mole per cent during the sampling period.

Samples for reduced sulphur from each of the treater stacks were taken under two different conditions. With the units operating and the flame lit, no reduced sulphurs were detected. With the unit operating but the flame unlit, H_2S averages of 190 parts per million (ppm) for the south treater stack and 107 ppm for the north treater stack were recorded. The Skinners contended that this was significant because the pilot flame relight did not function 100 per cent of the time.

The Skinners' analysis of the gas vapour in the enclosed produced water storage tank showed H_2S concentrations of 12 mole per cent were possible if the tank was leaking or if the thief hatch was open.

The Skinners stated they had experienced ongoing odours from Amax's batteries, wells and facilities since 1987. They indicated that the odours were mainly from the 10-16 battery and have ranged from light petroleum smells to very strong sulphur smells. The Skinners submitted a chronology of some of the odour events:

- 1988 - 1989, Amax operators were opening tanks lids to measure contents. Coincidental with these odour episodes, health effects were noted in the Skinner dairy herd, such as pink eye and clouded corneas, with the highest occurrence of corneal opacity during the 1989-90 winter.

---

[1] Alberta Clean Air Act & Regulations

- April 1990, Skinners complained about odours to the ERCB and started documenting odour occurrences. Ten odour events were recorded by the Skinners over the next 4 months.
- August 1990, the air monitoring trailer was installed. Five odour events were recorded by the Skinners.
- September 1990, five odour events were recorded by the Skinners and the monitor showed several infractions.
- October 1990, eight odour events were recorded by the Skinners. The most severe occurred on 11 October 1990. The flare blew out, the odours were strong and they accumulated in the bottom of the calf pasture.
- December 1990, black smoke, resulting from a VRU upset, was sucked into the milking barn by its ventilation system.
- 20 December 1990 to 16 January 1991, persistent strong odours occurred due to extremely cold weather and related malfunctions at the 10-16 battery. The odours were not recorded by the monitor but were noticed by the Skinners in the vicinity of the cow barn and the area where dry cows and heifers were kept. Twenty odour events were recorded by the Skinners for the months of December and January.
- February 1991 to June 1991, nine odour events were recorded by the Skinners.
- July 1991 to January 1992, fourteen odour events were recorded by the Skinners.

The Skinners conceded that the emissions from the treater and line heater stacks at the 10-16 battery now meet the current SO_2 guidelines. However, they did not believe that the proposed expansion would allow the 10-16 battery to continue to meet the maximum permissible SO_2 emission levels.

The Skinners submitted that during operational upsets they believed that the H_2S concentrations would be sufficient to cause odours but would not constitute a health hazard. The separation distance between the battery and the cow pasture should be increased, however, to allow for greater opportunity for dispersion of the H_2S and to thereby lower concentrations which may be present at the farm.

2.3.1.2 Views Of Amax

Amax submitted it had monitored wind direction, SO_2 and H_2S concentrations at three sites located near the 10-16 battery during the months of August, September, October and November 1990. Locations of the monitoring sites with respect to the battery, neighbouring oil wells and the Skinner dairy farm are shown in Figure 2. The data were analyzed to assess the general behaviour of SO_2 and H_2S emissions in the area.

With respect to SO_2, Amax submitted that during prevailing south winds, SO_2 readings were recorded by the monitor about 45 per cent of the time. This indicated that an SO_2 source was located to the south of Site A. Amax concluded that the source was the flare at the 10-16 battery which incinerates H_2S gas to SO_2. During prevailing south-east winds there were SO_2 observations at Site B about

10 per cent of the time and at Site C about 5 per cent of the time. It submitted that the SO_2 source of these readings was the Sparky battery located 650 m south-east of the monitor. During prevailing north-westerly winds Amax observed occasional SO_2 observations. Amax contended these SO_2 readings were from other local oil and gas production facilities not operated by Amax. The maximum hourly average SO_2 concentrations observed at Sites A, B and C were 90, 30 and 20 parts per billion (ppb), respectively. The Provincial maximum permissible hourly average concentration is 170 ppb.

With regard to H_2S, Amax submitted that there were several potential sources of H_2S in the area of the 10-16 battery and Skinner farm. It stated that H_2S observations at Site A tended to occur under both southerly and north-westerly wind conditions and indicated that the battery and the dairy farm, which lie in these general areas, are both possible H_2S sources. Amax added that high H_2S concentrations occurred at Site B most frequently during times which were characterized by north-west winds from the area of the dairy farm. Amax submitted that at Site C, H_2S observations were also recorded most frequently when winds were from the general area of the Skinners' milking barn. It stated that other H_2S sources, in this case well sites, also exist in directions north-north-east, east-south-east, south and west-south-west of Site B.

Amax observed that H_2S concentrations exceeded the Provincial maximum permissible hourly average concentration of 10 ppb on eight occasions, with a maximum H_2S concentration recorded of 57 ppb. Amax submitted that concentrations of this magnitude may constitute a nuisance but would not have any adverse health effects. It added that any nuisance effect should have since been ameliorated by its program to reduce fugitive emissions.

Amax concluded from a further analysis of the data that observations of H_2S at Site A were most frequent during day time hours. They concluded that the sources likely resulted from activities associated with upgrading of battery facilities. This upgrading was part of its program to reduce fugitive emissions. It also concluded that the observations of H_2S at Site C showed a pronounced diurnal variation, occurring most frequently during morning (0700 - 0900 MST) and evening (1800 - 2000 MST), and therefore possibly were related to activities of the dairy operations.

Additional air quality data were collected by Amax from January to July 1991 at an air quality monitoring trailer located 150 m north of the 10-16 battery and 300 m south of the midpoint of the Skinners' dairy farm. Amax submitted solution gas is combusted at the 10-16 battery for the purpose of heating oil and the combustion products are vented through stacks. It added if all the H_2S is combusted then the stack effluents will contain SO_2 but no H_2S. It further added if there is incomplete combustion, stack effluents will contain H_2S. Amax concluded that effluents from the stacks associated with the 10-16 battery are the only local source of SO_2.

Amax submitted that the observed median values of 10 ppb of SO_2 and 1 ppb H_2S measured during this period were very small. Elevated H_2S and SO_2 concentrations were observed together about 18 per cent of the time when the wind was from the south. The fact that SO_2 and H_2S were observed together suggested that the combustion of solution gas was not always 100 per cent effective. Maximum H_2S concentrations of 38 and 32 ppb were observed when winds were from the south-southeast and south, respectively, the general direction of the 10-16 battery. Maximum H_2S concentrations observed at the farm under these conditions were 7 ppb. A maximum hourly average SO_2 concentration of 330 ppb was recorded at the monitoring trailer, which was calculated to decline to 40 ppb at the dairy farm.

Amax submitted that high concentrations of SO_2 tended to be associated with moderately high wind speeds and that these SO_2 readings were generally associated with H_2S. It believed that the tendency for higher SO_2 readings to occur at high wind speeds is due to stack downwash, where the wind forces the emissions down the leeward side of the stacks. Because elevated H_2S concentrations occurred under both high and low wind speed conditions, Amax concluded that the H_2S originated from both ground based (e.g. fugitive emissions) and elevated sources (e.g. incomplete combustion within the stacks).

Amax conducted a study to determine if high wind speeds caused incomplete combustion. The study indicated that incomplete combustion is not a function of wind speed. It also considered incomplete combustion as a function of time of day. Incomplete combustion was observed about 50 per cent of the time during early morning hours and about 20 per cent of the time in the late afternoon.

Amax assessed the results of stack emission tests conducted at the 10-16 battery during the first part of September 1991 and confirmed that stack emissions are a source of H_2S due to incomplete combustion. Maximum H_2S concentrations at the dairy farm from the stacks were calculated to be about 11 per cent of those observed at the monitoring trailer due to the dispersion which occurs over the distance between the trailer and the farm.

Amax submitted surveys of emissions from the treater and the line heater stacks. Effluent from these stacks results from the combustion of solution gas which contains 4.24 mole per cent H_2S. The battery currently generates about 1300 cubic metres per day (m^3/d) of solution gas. Any solution gas which is not consumed as fuel in the treater is directed to the flare stack. Historically, solution gas production varied from 945 m^3/d to 2100 m^3/d and all of the gas was used in the treater and line-heater. Approximately 900 m^3/d of rural gas co-op natural gas is now purchased as fuel to supplement the treater fuel and for use as instrument gas.

Amax stated that treater stack emission parameters such as gas temperature, exit velocity and SO_2 flow rate depended upon whether one or both burners were operating. Amax estimated that SO_2 would be emitted at a rate of 1.08 kilograms per hour (kg/h) if one burner was operating continuously and assumed that emissions from the second burner would be similar. It also assumed that solution gas would be distributed evenly between the treater and the line heater. Amax concluded that this meant the line heater SO_2 emission rate would be 2.16 kg/h and the combined emissions from the treater and line heater stacks would be approximately 4.32 kg/h.

Amax noted that the stack exit velocities at the 10-16 battery were very small. When wind speed exceeds the exit velocity, stack effluent will be caught by vortices in the lee of the stack caused by this wind speed and directed toward the ground (downwash). The extent of downwash is a function of the ratio of wind speed to exit velocity. Amax stated that because exit velocities are small, downwash effects will be considerable. It believed that effluent from the treater and line heater stacks would be brought to the ground at wind speeds greater than 4.5 metres per second (m/s) (16 km/h). Under these conditions the emissions would act as a ground based source. This assumption was in agreement with the experience of the stack samplers who smelled SO_2 at heights well below stack top levels.

Amax calculated the SO_2 diffusion from the 10-16 battery assuming that the SO_2 was a ground based source. Estimates of ground level SO_2 concentrations suggested maximum SO_2 concentrations of about 300 ppb for wind speeds of 4.5 m/s. This value compared closely to the actual observed maximum hourly concentration of 330 ppb. Amax stated this close agreement supports the assumption that SO_2 stack emissions at the 10-16 battery act as a ground based source.

Amax submitted that the results of the dispersion calculations using Alberta Environment's STACKS 2 model predicted that hourly average ground level SO_2 concentrations resulting from flaring 945 m^3/d of solution gas should not exceed values of about 22 ppb, and that current operations of its 10-16 battery flare is consistent with the maintenance of desirable air quality. Amax concluded that past exceedances of Provincial air quality standards were the result of very low exit velocities from the stacks and that these exceedances should only occur in the vicinity of the battery. Amax stated that the stacks at the 10-16 battery would be upgraded to address the downwash problem (Appendix B).

On 15 July 1991, with prevailing winds from the direction of the dairy farm, Amax observed a maximum H_2S concentration of 7 ppb. As the monitoring trailer is some 300 m downwind from the dairy farm, Amax suggested that the H_2S concentration at the source could be significantly greater. Amax hypothesised that one source of H_2S could be the manure lagoon because of anaerobic decomposition of liquid manure. Findings of other studies have found concentrations of H_2S in excess of 1000 ppm to be occasionally associated with manure gases.

Amax contended that fugitive emissions from the 10-16 battery were well below Provincial standards and although it acknowledged that emissions have occurred, they have not presented a health risk to humans or animals. Amax concluded that its 10-16 battery was no longer a significant source of H_2S emissions. It suggested this is a result of efforts made in the previous months to reduce fugitive emissions at the 10-16 battery.

2.3.1.3 Views Of The Interveners

The Alberta Environmental Centre questioned the value of only measuring levels of SO_2 and H_2S when trying to determine possible affects from a sour oil development. Their concerns centred around the unknown behaviour and effects of complex mixtures of sulphur and hydrocarbon-based compounds.

2.3.1.4 Views Of The Board

The Board is of the view that the monitoring program carried out by Amax represented a reasonable effort to detect and record potential emissions of H_2S and SO_2 from the facilities. The Board also concurs that the levels of H_2S and SO_2 recorded by Amax were generally at a "nuisance" level and not high enough to represent a risk to life or health. The potential affect on the dairy herd health is discussed later in Section 2.3.4.

The Board also accepts the view of the Skinners that the family experienced strong odours that were not recorded on the monitoring devices. The Board does not believe that this was due to any failure of the monitor or monitoring program. Rather, the Board is of the view that a broad range of meterological conditions, when coupled with the fixed location of the monitoring points and the use of hourly average calculations would likely have resulted in some under-reporting of the recorded emissions experienced by the Skinners in both intensity and frequency.

The Board notes that Amax concluded that there was a correlation between its operations and elevated levels of H_2S and SO_2 at the monitoring points. The Board also accepts the evidence of the Skinners that several areas of the 10-16 battery represented potential sources of both reduced sulphur and SO_2. The Board is of the view that several factors associated with operation of the 10-16 battery were sources for the odour events noted by the Skinners. The Board accepts the Amax evidence that stack downwash was one potential source. Other historical sources were very likely to have included failures in the VRU and, in particular, the frequent failure of the thief hatches on the produced water and oil storage tanks. The Board does not believe that the Skinner dairy farm operations, and in particular the dairy barn and manure storage lagoon, represented significant sources of H_2S. While the Board can accept the evidence that under certain conditions manure may produce significant concentrations of H_2S, the regular operations on the Skinner farm did not appear to create such conditions. For example, the lack of agitation and open-air storage of manure would strongly suggest that released levels of H_2S would be low.

Both Amax and the Skinners observed that there had been a reduction in detectable emissions at the dairy farm. This appears to have resulted from a number of improvements made at the battery. The Board accepts the commitments made by Amax to continue to look for other areas where improvements can be made, such as stack redesign. The Board accepts the view of both parties that the current and proposed changes will allow Amax to meet the existing air quality standards at current levels of solution gas production. The Board is of the view that should permission be granted to continue operation of the 10-16 battery, Amax will be expected to respond immediately and effectively to detectable odour incidents, whether or not the levels measured at the Skinner farm are below Provincial standards. The Board will also expect Amax to proactively initiate all steps needed to end excess emissions, including facility shutdown, when it is not possible to immediately implement the appropriate technical improvements. Finally, the Board will expect Amax, in discussion with the Skinners and ERCB field staff, to review their air quality monitoring program. Any future program will be required to be sufficient to provide an early indication of possible odour events or other exceedances within the Skinner farmstead. The Board will also review, with Alberta Environment, the parameters which should be measured.

2.3.2 Subsurface Impacts

2.3.2.1 Views of the Skinners

The Skinners estimated they use about 5000 gallons per day (gpd) of water from the three wells that currently supply the dairy. They expressed concern regarding the impacts that the existing oilfield operations may have had on groundwater quantity and quality, and the potential adverse impacts of continued and expanded oilfield activity.

With respect to water quantity, the Skinners argued that the drop in their water well levels could not be attributed to their use of the aquifers or to climatic conditions, but rather was caused by the drilling and completion of oil wells through these aquifers which created flow paths which allowed the water to drain from the upper aquifers into lower formations. Calculations of relative pressures and pressure gradients were presented to reinforce the theory that it was possible to have this drainage occurring.

Witnesses for the Skinners argued that groundwater quality had also been adversely affected by other oilfield activity. They stated that with fluids such as oil and water which do not readily mix, the oil can move in directions different than the regional or local groundwater flow. Consultants for the Skinners argued that plumes of pollution caused by oilfield activity could be migrating towards their water wells and cited elevated levels of chlorides in the 8-16 water well as evidence. It was noted that chlorides are a good parameter to use as an indicator of groundwater pollution, in part because the concentrations of chlorides in the aquifers being used by the Skinners are very different than in the deeper aquifers and in the hydrocarbon bearing zones. The characteristics of chlorides include being very mobile in the soil-water or groundwater. The presence of total petroleum hydrocarbon (TPH) and phenols in trace amounts in the Skinners' water wells was suggested to be further evidence that the water quality of their wells had been affected.

The Skinners argued that the surface clays below the farm site and oil facilities were not as impervious as Amax suggested. They submitted that the elevated levels of nitrates found in the slough were a result of calcium nitrate being used as a soil amendment on salt-water spills. In addition, they suggested potassium nitrate which was sometimes used as a component of a drilling fluid, was being displaced in the soil by sodium and calcium following salt-water spills and ensuing reclamation efforts, and was the source of elevated potassium levels in the slough.

2.3.2.2 Views Of Amax

Amax conducted tests in August 1991 on the seven water wells (Figure 2) located on the farm. Based on its monitoring at that time, it estimated a water use rate by the Skinners of about 3500 gpd and noted that the use of water fluctuates according to the number of animals on the farm and increases during the winter months. Amax agreed with the Skinners estimate of 5000 gpd as being within the likely range for water use rate. Amax argued that while water levels in the wells had dropped 1 to 5 m from those levels recorded in the water well drilling logs, this would be consistent with the continuous use of the aquifers by the Skinners. Based upon these results no appreciable lowering of the water table due to oil and gas activity had occurred. Amax did not believe it was responsible for the reduced water levels in the Skinner aquifers and submitted that the drilling of petroleum wells had never been shown to cause the de-watering of any aquifer in Alberta.

The effect of oilfield activity on groundwater quality was also addressed by Amax. Amax argued that based on water analysis done on one of the Skinner wells in 1972, which indicated a chloride level of 16 ppm, and tests done in 1991 which ranged from 3 to 14 ppm, that there was no change to the chloride levels. Because chlorides are so closely related to oilfield activity, this in its view indicated no impact on water quality resulting from oilfield activity. Amax suggested that the Skinner wells were on a hydrographic high and therefore the regional water flow was away from the wells. It argued that even if the Amax wells were causing groundwater pollution, the results would not show up at the Skinner wells.

Amax also argued that the area subsoil was primarily an impervious clay layer of some 4 to 30 m in thickness and that this clay layer prevents oil and salt-water spilled on or near surface from entering the groundwater system.

Amax indicated that although unlike chloride there were no baseline values for either TPH or phenols in the Skinner wells, the trace levels observed were in the range frequently encountered as background levels in east-central Alberta, and were likely naturally occurring. One sample did have phenols at a level about five times the detection limit and the value found was confirmed by re-analysing the sample. Amax could not explain this occurrence. Upon re-sampling this well, Amax found phenol levels were at or near the detection limit, similar to results obtained from other wells tested.

2.3.2.3 Views Of The Board

With regard to groundwater quantities, the Board notes that both parties agreed with the average annual groundwater volumes being used by the Skinners for both domestic and agricultural consumption. Both parties also concurred that draw down has occurred in these wells. After reviewing the evidence provided by both parties, the Board accepts the Amax position as the most reasonable. Their witnesses contended that the observed degree of draw down can be explained by the relative difference between water withdrawal rates by the Skinners, discharge rates from the aquifer, and the recharge rates into the aquifers. The Board does not accept the hypothesis of the Skinners' witnesses that oil wells in the area provide a significant opportunity for downward migration of groundwater at the Skinner wells. Nor can the Board conclude that the drilling of additional oil wells, assuming existing regulations are met, would result in any material increased risk of adversely impacting groundwater quantity. Further, the Board does not accept the hypothesis of the Skinners' witnesses that reservoir pressure reductions as a result of oil production from the Sparky and Dina pools causes fluids such as groundwater from upper formations to migrate to those produced pools.

With regard to impacts on groundwater quality, the Board could not find any compelling evidence that the quality of water in the Skinner water wells had been negatively impacted by oil and gas activity. The lack of elevated chloride levels, which witnesses for both parties agreed would be an excellent tracer for oilfield pollution, was particularly notable. The Board has difficulty accepting the hypothesis of the Skinners' witness that phenols and petroleum hydrocarbons were detected in the Skinner water wells due to the migration of Dina and Sparky formation waters, while chloride levels, which were at much higher concentrations in the formation waters, were not elevated in any of the water wells tested.

While the Skinner water wells do not appear to have been negatively impacted by the Amax oil operations, the Board can appreciate the family's concern. The Board will require Amax to meet its commitment to develop an ongoing sampling program to continue to ensure the Skinners' well water and surface water quality remains high. The program will be developed in consultation with the Skinners and the ERCB in order to ensure that the sampling is effective and efficient. The Board will also initiate discussions with Alberta Environment to determine the need for research into methods for measuring low levels of organics such as petroleum hydrocarbons and phenols, and for establishing natural background levels of these compounds, particularly in the Provost area.

2.3.3 Surface Impacts

2.3.3.1 Views Of The Skinners

The Skinners submitted that they have incurred extensive agricultural and surface impacts over the years as a result of the Ladd and Amax operations on Section 16. They stated that the problems caused by the Amax facilities, wells, pipelines and contractors as they currently exist do not allow the Skinner dairy and families to reasonably coexist with the oil operations. They stated that in the past Amax took a reactive approach to its operations and would only address a problem if the Skinners complained. It was their view that there would always be unacceptable impacts from the 10-16 battery, satellites and related wells as long as they were operating in proximity to the dairy farm. Further, the Skinners believed it would be unlikely that Amax would be able to implement an effective proactive approach to addressing problems before they occur. They submitted that one or the other of the industries must be removed.

The Skinners stated that dust has been an ongoing problem resulting from oilfield traffic in and around the farm. They agreed that since the main Amax access road was relocated in 1990, the dust problem has improved although it recurs when activities such as well drilling and servicing take place. Since many of the wells and facilities are located near or within the Skinner bowl, dust commonly disperses throughout the area. The Skinners believed the dust has affected herd health.

The Skinners described numerous oil and salt-water spills that occurred as a result of facility upsets, poor operating practices or faulty materials and equipment. They stated the spills have had an adverse effect on soil quality, crop production, and surface and groundwater. The Skinners argued many of the wellheads on Section 16 leak, the Sparky pipelines have ruptured on several occasions, a salt-water tank at the 10-16 battery ruptured and released salt water for an extended period of time, spills have occurred from drilling and servicing operations and most of the spills from the oil operations have been covered up rather than properly reclaimed. They argued that elevated potassium and chloride levels found in their watering slough are the result of the numerous salt-water spills that have occurred from either Sparky or Dina produced water. They stated that it was clear from Amax's own evidence that oil and salt-water pollution has occurred on Section 16. They did not believe that the spills would cease to occur with the implementation of Amax's 24-point plan (Appendix B) for continued operations and development. They argued that additional wells and production could only increase the risk and occurrence of oil and salt-water spills.

The Skinners expressed concern with the open sump located at 9-16 and the potential contamination of the subsoil and groundwater from the drilling fluids. They submitted that the fluids should be removed from the sump and the sump reclaimed.

The Skinners submitted that when Amax prepared the surface location for Pad 1 in 1990, it did not notify them that it would remove a stand of aspen trees located near the 10-16 pad site until after the trees were pushed down. They were advised that the trees were removed to accommodate the borrow pit that was required for fill material and for future drilling operations. The Skinners rejected Amax's offer to replace the trees because they interpreted the offer as being conditional upon their agreement to withdraw any objections to the production of the Pad 1 wells. They also felt that as the area has now been levelled and stabilized, any further activities by Amax may only create more problems. The Skinners were inclined to let the natural vegetation re-establish itself at its own pace.

The Skinners believed that as a result of the operation of the five wells on Pad 1, the immediate area surrounding the pad, referred to as the calf pasture, has been rendered unusable for agricultural purposes. They contended that the area is continually disturbed because of periodic well service operations and the frequent attendance by Amax staff and contractors. They do not use the calf pasture area for its intended purpose as it is not possible to satisfactorily coordinate the operations of both land users. The heavy equipment and frequent vehicle traffic disturbs the land surface, thus further affecting their ability to use the area for agriculture.

Well service operations were described by the Skinners as a major source of disruption to the dairy operation and farm life. They stated that with over 30 wells on Section 16, there are service rigs and related vehicles continuously driving in and out of the area. They had particular concerns respecting the large number of service personnel. They stressed that it is unsettling to have strangers on their land on such a frequent basis.

The Skinners submitted that weed control around the Amax operations is poor. They described weed problems to exist at most of the well sites and specifically identified poor control at 14-16, 11D-16, 15B-16, 10C-16 and 11A-16. They stated that the weeds spread into the cultivated fields from the Amax well sites and facilities. The Skinners control weeds around the farmstead by applying a herbicide, however, the application of the herbicide must be timed to the budding stage of the weed or it will not be effective. After the application of the herbicide, the Skinners maintain control of weed growth by mowing. They believed that Amax's control of weed growth by mechanical means could be effective only if it is rigorously employed and timed before the weeds go to seed.

A witness for the Skinners claimed to have detected the herbicide "Picloram" in water samples taken from the slough. It was pointed out that Amax had used this herbicide for weed control in 1987.

The Skinners described the fencing of some wells to be inadequate and that belt guards for some electric pumps are not in place. These problems pose a hazard to the cattle and, on some occasions, the lack of fencing and other oilfield activities has resulted in injury to cattle, particularly calves. They stated that in one case an animal had to be destroyed.

2.3.3.2 Views Of Amax

Amax submitted that in the past it had recognized and responded to any concerns expressed by the Skinners in a manner that would reduce or eliminate surface impacts caused by its operations. It stated that it had endeavoured, to the best of its ability, to correct the problems as they occurred. It also stated that its 24-point plan (Appendix B) for continued operation of the battery and development of the Dina takes into consideration the concerns that the Skinners have expressed in their submissions to the Board. The concerns that it responded to or has addressed in its plan include those related to excess traffic and dust from its access roads, soil degradation, oil and salt-water spills, excess tree removal, tank and pipeline ruptures, sterilization of lands for agricultural uses and problems caused by service operations.

To address the traffic, safety and dust problems from the original access route, Amax relocated its main access road to the 10-16 battery and nearby facilities in 1990. The original main access road entered the section from the west side and passed by all Skinner residences and farm buildings. A new road was constructed that entered the section from the south, bypassing the residences and dairy farm. This effectively eliminated most of the traffic problems caused by the old road, significantly reduced the dust conditions in the Skinner bowl and provided a greater degree of safety for livestock and people in the Skinner farmstead area.

Amax stated that throughout its operations in the Hayter Field it has modified or replaced certain of its facilities that have caused spill problems. Amax also retained the services of soils and site reclamation consultants to ensure that spill locations are fully reclaimed. It believed that the incidence of spills has been reduced considerably in recent years as a result of these efforts. Amax discussed several pipeline breaks that had caused salt-water spills in the past. Amax stated that the troublesome lines were related to the Sparky system, and that the Sparky lines had been replaced with internally lined pipe to limit salt-water corrosion. It stated that all the Dina pipelines were originally installed with internal liners and, to date, have not experienced corrosion problems. In addition, cathodic protection has been installed on all pipelines in order to minimize corrosion. Amax also replaced a ruptured underground salt-water tank located at the 10-16 battery. To reduce both the incidence of leaking and noise from hydraulic lines and pumps, Amax changed over all of its hydraulic powered well pumps to electric power. Its operators also conduct a daily visual check of the wells, stuffing boxes and other potential spill sources.

With respect to its drilling sump located at 9-16, Amax stated that it is currently unused although it planned on utilizing the sump during the drilling of future wells. It did not believe that the sump created an undue environmental hazard as the drilling fluids did not contain invert materials and the subsoil is comprised of a clay till that effectively contains the fluids in the pit. A fence is located around the sump to prevent cattle from entering.

Amax submitted that it has specific procedures in place with respect to reclamation of oil and salt-water spills and it disputed the Skinners claims of large quantities of salt water being discharged as a result of tank and pipeline ruptures. For example, based on its analysis of soil samples from immediately around the 10-16 underground tank, Amax calculated that approximately 0.5 m^3 salt water had been released to the sub-soil from the rupture. It identified several oil and salt-water spills that have been under reclamation since the spills occurred in the early 1980s. Oil spills occurred at 2-16, 6-16 and at the 10-16 battery (oil spray). Salt-water spill sites are located at 1-16, 2-16, 4-15, 6-16, 7-16, 8-16, 10-9 (2 spills) and 10-16 (tank rupture and spills around wellheads).

Amax submitted that the results of its spill reclamation program has shown a favourable return to previous soil quality and productivity at most of the spill locations, although many of the sites will require continued reclamation. The 7A-16 site in particular has not shown a reduction in areal extent or a return to normal conditions.

Amax noted that there was a question as to its right to remove a stand of aspen trees that was located on 10-16 for the purpose of obtaining fill material for construction of its 10-16 well pad (Pad 1, Figure 2). It believed that it had the right pursuant to a surface lease agreement with the Skinners. Notwithstanding that belief, it stated that it had offered to replace the stand of trees and is still prepared to do so. Amax argued that it did not intend to make the replacement of the trees conditional upon the Skinners' approval of the production of the four wells that were drilled from that site.

With respect to the concerns regarding the impacts from service operations, Amax stated that it services its wells during daylight working hours avoiding noise at night, uses methods that minimize odours, including the use of sweet completion fluid and closed tanks for swabbing and endeavours to keep noise from the service rigs to a minimum. It stated that each of the Dina wells on Section 16 requires a service operation approximately once every 12 to 18 months and the operation takes from six hours to two days to complete.

Amax did not believe that its service operations would effectively prevent the agricultural use of the land in the vicinity of the five wells on Pad 1. In the future, due to the short duration of the service operations, the service rig would be situated on a gravel pad and the fence surrounding the pad would be reduced in size. Amax believed this would allow the Skinners to use most of the area to pasture their calves as they have done in the past. It also stated that it would coordinate its service operations with the Skinners to further reduce any conflicts with the dairy operations.

Amax submitted that it has not used chemical weed control on any of its battery or well sites since 1987. Mechanical means are now used to control weed growth and will continue to be used. It did not believe that the alleged presence of the herbicide Picloram in the Skinners' slough was a result of its chemical weed control in 1987, because Picloram will rapidly decay in the presence of oxygen and light and is not a persistent chemical in water. It stated that its analysis of the Skinner slough showed no evidence of Picloram.

In response to a concern raised by witnesses for the Skinners that the slough had elevated nitrate concentrations, Amax said that such levels of nitrates are expected in a slough with considerable biological activity. Further, potassium is a natural component of salts and will eventually find its way into the slough. Amax concluded that any changes or alterations in the water quality of the slough is not attributable to petroleum activity. It further stated that it did not find any indication of chlorides, sulfides, or petroleum hydrocarbons in the slough attributable to petroleum activity.

2.3.3.3 Views Of The Interveners

The Alberta Environmental Centre expressed concern respecting the affects of the Amax operations on soil quality on the Skinner farm and the impact of oil and gas operations on soil quality throughout the Province. The impacts that it identified were soil degradation, as a result of soil compaction, and contamination caused by oil and salt-water spills. Soil compaction results from the use of heavy vehicles and machines on the land. Compaction remoulds the soil and destroys soil structure thus affecting the hydrologic properties of the soil, moisture retention and ability of plant roots to penetrate the soil. It stated that salt-water spills affect the soil by dispersing clay particles which in turn changes soil structure and decreases water infiltration. Oil spills cause water repellency that prevents water infiltration and reduces aggregate stability within the soil. They suggested that Amax should include soil and water resource planning in designing its facilities, cause minimal disturbance to the land surface and immediately reclaim areas that have been disturbed or polluted.

2.3.3.4 Views Of The Board

In the Board's view, the past operating practices of Amax and Ladd were lax and generally reactive. Until recently, Amax appeared to show little sensitivity in responding to the concerns raised by the Skinners regarding the oil activity on their farm. It was Amax's position that its more recent operational improvements and new commitments (Appendix B) would deal with most of the Skinners' surface impact concerns. The Board agrees that many improvements have been made and changes such as the use of electrically-driven screw pumps will reduce noise and other impacts. Similar improvements in other operational areas were acknowledged by the Skinners. However, the Board accepts the view by the Skinners that working relationships will be difficult to mend given the lack of trust between the parties.

The Board accepts the Skinners' contention that, even with relocation of the primary access road, some ongoing impacts from the dust and noise will be associated with these operations particularly within the Skinner bowl.

The Board agrees with the position of the Skinners that both salt-water and oil spills have occurred frequently at the Amax operations. Of the two, salt-water spills appear to have had the greater impact on soil fertility. In general, cleanup of salt-water spills appears to have been initiated promptly. The improvements made by Amax in the quality and type of pipe used to reduce corrosion will likely reduce spill frequency. A more aggressive approach to salt-water spill cleanup may be appropriate. This is particularly important if spill frequencies and/or volumes remain high. The Board will instruct ERCB field staff to review this possibility with Amax.

Oil spills, particularly at the 10-16 battery, although less frequent than salt-water spills, are also of concern to the Board because of the past magnitude of the spills, the risk of fire and the associated health and safety risks. On at least two occasions liquids have sprayed from the 10-16 battery flare stack. In one case, the oil ignited and burned a portion of the adjoining field. The proximity of the Skinners' farm buildings and dwellings to the 10-16 battery make similar occurrences unacceptable.

The Board does not believe sufficient diligence has been shown to provide confidence that this could not occur again.

Both parties discussed at length the impact of surface runoff from spills and leaks on water quality in the slough. The Board does not believe serious degradation of surface water quality has as yet occurred. The Board supports the concern of the Skinners that the quality and quantity of their water supply must be protected. The Board believes that without adequate mitigative measures, the ongoing loss of oilfield-associated fluids could eventually threaten surface water quality. At particular risk is the large slough which serves as an important source of water in the summer for the Skinner dairy herd. It is reasonable to expect, given the natural area slopes and drainage, that any materials spilled within the bowl could eventually migrate into the slough. This would be particularly true along roadways and other areas of compacted soils.

The Board understands the Skinners' concern that the herbicide Picloram was detected in the slough. However, given that Picloram does not remain stable for long in the presence of oxygen and light, the Board finds it difficult to accept its presence in the slough if it has not been used for weed control in the area since 1987.

The Board recognizes that leaking screw pumps have been a problem in the past. However, it is unclear from the evidence whether or not produced oil has leaked from wellheads. The Board notes that Amax has changed all of its hydraulic-powered pumps over to electric power and believes this should eliminate the problem of hydraulic fluid leaks at the existing wellheads.

With regard to loss of agricultural land the Board notes that, in general, surface lease payments to the landowners are intended to be adequate to compensate for the interim loss of the land. In this case, the Skinners did not claim that Amax had failed to provide lease payments or were operating beyond the boundaries of their leases. Therefore, Amax was likely operating within its rights. The Board does, however, encourage all oil and gas operators to minimize the surface area disturbed by their operations, if only to reduce future surface reclamation costs. The Board would encourage Amax to do the same at existing and potential future sites. The Board notes Amax's commitment to increase communication with the Skinners and strongly encourages this initiative. Such communication in the past would likely have greatly reduced conflicts such as the dispute over the extent of tree clearing associated with the removal of fill material for construction of the 10-16 pad.

With respect to the off-site sump located at 9-16, little substantive evidence on the condition of the sump was submitted by either party. While the Board did visit the site during the hearing, the sump was snow covered. Accordingly the Board will have its field staff assess the sump's condition, including the suitability of its location compared to other possible locations, contents, fencing, future use, and need for reclamation. The Board accepts Amax's statement that the sump was not used for storage of invert muds and it would not permit the use of this sump for that purpose. The sump must be properly fenced so as to not pose a hazard to livestock.

The Board accepts the Skinner position that general site maintenance by Amax, including weed control and fencing, has not been carried out well. The Board notes that several sites have become overgrown with weeds and will require Amax to address this problem. The Board notes that since 1987 Amax has controlled weeds by mechanical means and it believes this method can be effective if applied conscientiously. The Board also believes that fencing and proper placement of pump guards has not been adequate to permit safe agricultural activity in the area surrounding the well sites. Amax will be required to consult with the Skinners on the need for fencing at its existing well sites and ensure that guarding is in place to reduce potential hazards.

2.3.4 Effects On The Dairy Herd

2.3.4.1 Views Of The Skinners

The Skinners argued that past oil field operations were having an observable impact upon the health and productive performance of their dairy herd. They stated that from 1988 to 1990 corneal opacities were experienced in the milking cows, which are housed close to the 10-16 battery. They also experienced a number of cases of "downer" cows. Both of these conditions did not respond to common veterinary treatments. The Skinners argued that emissions from the 10-16 battery were the primary cause of these adverse impacts. Witnesses for the Skinners acknowledged that, based on research evidence, considerably greater concentrations of H_2S or SO_2 than those observed or predicted to have occurred at the farmyard would have been necessary to cause such symptoms in cattle. Notwithstanding this, they speculated that the corneal opacities could be the result of irritation by a mixture of sulphur compounds and hydrocarbon vapours from the 10-16 battery.

Herd records were presented to describe the abortion rate of the herd. The Skinners argued that the abortion rate was abnormally high during the period of battery upsets lending further evidence to their position that emissions were having a direct, negative physiological effect on their herd. The Skinners believed that bovine virus diarrhoea (BVD), which Amax hypothesised as a possible cause of eye lesions and abortions, was not a reasonable explanation because the other symptoms commonly associated with BVD were not present. Furthermore, they argued that BVD would have to be at a very advanced stage to cause the number of abortions or the severity of eye lesions observed and so the disease would have been readily detected if present.

With regard to productivity, the Skinners argued that the milk production data, while showing a gradual increase prior to 1987, should have exhibited a greater rate of increase since that time. The Skinners agreed that a modern dairy cow is already under a considerable amount of stress as a result of management to maximize milk production. Incremental stresses from oilfield facilities or activities, including noise or reduced air quality, they believed, could readily result in additional stress sufficient to reduce milk production. The Skinners said that the stress from oilfield operations is one of the causes for the lower-than-expected milk production exhibited by the herd between the summers of 1987 and 1991. The Skinners agreed a general increase in milk production had occurred during this period but contended that the increase was much lower than would be expected. They argued that the expected increase in production from improved genetics and good management between 1987 and 1991 was not fully realized primarily because of the impacts of the Amax operation.

The Skinners also argued that their management response to the problem of poor dairy performance was to increase the cull rate. They contended that their herd's cull rate was much higher than what would normally occur in a similar herd. By utilizing this technique of replacing lower than average performing cows, including cows with either low milking and/or reproductive abilities, they were able to maintain their quota volume. They maintained, however, that this strategy produced an undue economic hardship.

2.3.4.2 Views Of Amax

Amax concurred that overall the herd was well managed. Amax argued that the average milk production had increased over the period in question and that the fluctuations observed were normal for a high producing dairy herd. They also observed that with a well managed, high performing dairy herd, many variables come into play. It was not realistic, Amax contended, to expect a consistent, preconceived productivity increase in a herd.

Amax noted that the concentrations of H_2S or SO_2 possibly accumulating at the farmsite from its operations were at least one order of magnitude lower than the concentrations known to cause the symptoms observed in the Skinner cows. Amax also contended that the dairy farm was itself a source of H_2S emissions.

Amax argued that the suggestion that a complex mixture of emissions could reduce the effective dose of H_2S or SO_2 required to cause toxicological symptoms, while possible, was at best speculation. No comprehensive evidence with respect to complex mixtures was presented. Amax suggested that the eye lesions observed would more likely be caused by BVD and that this would also explain the high incidence of abortions and poor milk production alleged by the Skinners.

Amax argued that the cows presented on the "list of abortions" filed as evidence by the Skinners should rightly be considered possible abortions because the pregnancies had not been verified. Furthermore, Amax suggested that independent third party confirmation of alleged abortions would have been preferred, and noted that distinguishing early-term abortions from unsuccessful impregnations was difficult and subjective.

Regarding the issue of oilfield related stresses on the dairy herd, Amax argued that under modern high intensity agricultural practices, each cow is placed under such demand to maintain production that any number of factors or changes to those factors, including management inputs, could cause a reduction in performance. Furthermore, there is no research which showed that oilfield related factors increased the stress level of dairy cows.

Amax argued that a high cull rate could be indicative of good dairy herd management practice. In this case, the Skinners very successful calf rearing ability coupled with some years with higher than average numbers of female calves resulted in a large number of replacement heifers being available for use in the herd. Thus, with the large number of genetically superior replacement heifers available, cows could be culled with no economic hardship.

2.3.4.3 Views Of The Interveners

The Alberta Environmental Centre contended that H_2S or SO_2 were not likely directly causing the symptoms observed. They supported the Skinners' "gas eye" theory, suggesting that complex mixtures of sulphur and hydrocarbons were the cause, but were unable to provide any confirming evidence. They stated that nothing is known about the composition of these mixtures or the dosage which may cause physiological effects. They also stated that emissions from other oilfield facilities in the area may have contributed to the problem.

The Alberta Environmental Centre argued that available experimental data, which are based on tests using single compounds such as hydrogen sulphide, were not particularly meaningful in this instance because the emissions represented a "complex mixture" of hydrocarbons and sulphur based compounds. They contended that such mixtures could have effects on herd health even when the concentrations of individual components were below the threshold of concern. However, they could not cite any direct or even inferential experimental data which would support their hypothesis.

The Alberta Environmental Centre concluded that the high cull rate experienced by the Skinners was the strongest evidence supporting their opinion that the Skinner herd had been affected by oilfield activities in the area. This high cull rate was, in their view, a management response to the problem. They agreed with Amax and with witnesses for the Skinners who were all of the opinion that the milk production records did not show a statistically significant difference in the level of milk production between the years in question.

2.3.4.4 Views Of The Board

With respect to physiological impacts on the Skinner dairy herd, insufficient evidence was available to convince the Board that the corneal opacities observed by the Skinners resulted from the Amax oilfield activities. However, the Board can accept that it is possible and the Board does accept the contention that no other more reasonable explanation, such as BVD, was provided at the hearing to explain the eye problems noted. In the absence of better evidence as to possible mechanisms, or a recurrence of the problem, the Board is forced to conclude that the real cause will likely remain speculative. The Board is not convinced that the dairy farm itself was such a significant source of H_2S that this could explain the eye symptoms.

With respect to the other health symptoms (i.e. increased rate of downer cows, increased abortion rates) the Board is comfortable accepting the Skinners' contention that these symptoms were real, but no evidence was presented which would either confirm or deny a linkage with oilfield operations. The Board cannot accept that the available evidence provides a definitive link between emission levels and effects on the dairy herd. While the effects appeared to be temporary, the Board believes some research effort should be encouraged to validate the speculations of some witnesses at the hearing.

The Board notes that none of the parties were able to supply a possible mechanism to link any of the observed physiological responses to the known releases of sulphur compounds and hydrocarbons from the Amax operations. The available experimental data indicate that the emissions released from the Amax batteries, satellites, and wells during individual events were not likely in sufficient concentrations to cause the physiological problems noted by the Skinners. It is possible that multiple exposures may have resulted in a cumulative effect and eventually evoked a response at an unknown exposure threshold but this is at best speculative. The Board also believes it is possible or even likely that the practice of highly selective breeding to maximize dairy cattle productivity has tended to also increase the sensitivity of dairy herds to all forms of environmental disturbance, both natural and man-made. In this case, the Board can accept the unique and unusual combination of the very intense sour oil development, the proximity of the two industries, the local bowl-shaped topography and the relative sensitivity of dairy cattle could have combined to magnify the impacts of the oilfield emissions to a level sufficient to produce a physiological response in the cattle.

It is worth noting that the health effects recorded during 1989-90 by the Skinners were no longer evident in the herd in 1991-92. Both parties agreed that significant improvements had been made in Amax's operations since that time. This would suggest a linkage does exist between herd health and

Amax's operations. It would also indicate that operation of the current Amax facility can be carried out in a manner that does not result in any obvious affect on herd health.

The contention of potential impacts by fugitive emissions from a sour oil facility on animals, and therefore by inference, possibly on human health as well, is a serious one. It is certainly one which the Board believes must be addressed. On one hand, the available experimental evidence did not support a conclusion that oilfield activity was the source of the problems. On the other hand, no alternative explanation was provided for the symptoms observed. Clearly there is significant public concern, particularly in the agricultural industry, about the potential impacts of oilfield emissions. Without clear data, however, the Board is unable to confirm that a linkage does or does not exist, much less determine the actual risks or which actions need to be taken to address these risks.

The Board is aware that the Alberta Cattle Commission (ACC) has recently commissioned a review of the available data on possible linkages between oil and gas industry emissions and livestock health. The study is being conducted by the Alberta Environmental Centre. As a first step in assessing the impacts of oilfield emissions on animal health, the Board intends to monitor the results of the ACC study. Once the study is completed, it is the Board's intention to meet with the various stakeholders, including both the energy and agriculture industries, to determine what the next appropriate steps might be to try to resolve this issue.

With regard to lost milk production, the Board accepts the Skinners' view that milk production, on a per animal basis, was potentially lower than might have been expected from 1987 to 1991. Statistical analyses, including those done by the witnesses for the Skinners, concluded that productivity did show a real, positive increase over this period. The Board is satisfied, however, that the rate of increase during that period was lower than would have been predicted.

A great deal of culling was carried out during this period. It is arguable that any suppressed improvements in milk production during the time of higher than normal culling rates will be compensated for in the future because of the overall improvement in herd genetics.

As to the causes for lower production, the Board believes it is possible that this may have been due to a direct response by the animals to the impacts (e.g. noise, dust, odours) from the nearby oilfield operations. However, this seems unlikely given that the milk-producing dairy cattle, particularly during the winter months, remain largely indoors and so would be isolated to a considerable degree from outside disturbance.

A second explanation for the reduced production during this period would be that production dropped because of less effective management practices by the Skinners. Witnesses from both sides agreed that modern dairy herd operations are complex and very susceptible to management changes. It was also agreed that high levels of stress in the dairy farmer could be directly translated into reduced production, due at least in part to a reduced ability to optimally manage the dairy herd.

During the period from 1987 - 1991, there was a marked deterioration in the relationship between the Skinners and Amax. There were numerous odour and other incidents, and a significant increase in the level of animosity and distrust between the two parties. It is almost inconceivable that this would not have had an impact on the Skinners (see Section 2.4). It seems reasonable to expect that the ability of the Skinners to optimally manage their farm would also have been affected, although such impacts may not have been evident to the Skinners. This in turn would readily explain the reduced rate of increase in milk production. The reduction in milk production which occurred in 1986 would seem to support this view. During the summer/fall of that year, the Skinners undertook a major construction project. While this was underway, milk production in the herd declined significantly, and the Skinners believed this was due to the associated loss of their ability to dedicate as much attention as normal to the management of the dairy herd. The Board believes that similar periods of reduced ability to optimally manage the dairy herd, for the reasons noted above, may have occurred during the period 1987-91. This, in turn, resulted in reductions in milk production.

2.4 Social Impacts

2.4.1 Views Of The Skinners

The Skinners expressed deep concerns about impacts of the Amax oil activity on their lives and lifestyle. The increase in oil activity resulting from the 10-16 battery construction and related operations has resulted in a feeling among the Skinners that they are losing control of their ability to manage the dairy operations and their lives on the farm. Among the social concerns expressed by the Skinners were the increased oilfield traffic on Section 16, and the attendant noise, dust and danger associated with that traffic. Related to this issue was noise from oilfield equipment, emissions and odours from the 10-16 battery in the farmyard, and constant worry about the 10-16 battery, particularly the possibility of fires and explosions. The Skinners further described a sense of loss of their country lifestyle due to the proximity of the oilfield operations to their residences and a related loss of a pristine country setting. They expressed uncertainty about the health effects that low level emissions may have on their families and the negative effects that the oilfield operations have had on their lives, their relationships within the extended family and the activities of their children. The Skinners described a loss of faith in Amax because of its ineffective and insensitive actions in dealing with the Skinners' objections. Of particular concern was a letter wherein Amax threatened legal action if the Skinners did not withdraw their objections to the ERCB concerning the four wells in Lsd 10-16. Although the Skinners felt that operations had improved, they remained unconvinced as to Amax's long-term corporate intentions and plans to deal with the family.

Evidence was presented by the Skinners that indicated, despite their best efforts at coping with the oilfield activity, it had been psychologically wearing. The effects included anxiety, depression and physical disturbances symptomatic of unremitting stress. Witnesses for the Skinners stated that all members of the Skinner family evidenced chronically elevated levels of stress sufficient to interfere with their daily lives. Stress levels in some members of the Skinner family were sufficiently high that it was suggested this could have some lasting deleterious effect on their physical and mental health. It was contended that if operations continue as they have, the Skinners would experience more stress.

2.4.2 Views Of Amax

Amax stated that they have both proactively and reactively responded to the Skinners concerns (Appendix A). In addition, Amax emphasized a desire on the part of operating staff to improve their operations wherever possible.

Amax also tendered a list of proposals they would implement upon the continued operation of the 10-16 battery and further development of the Dina pool (Appendix B). Amax contended that the list addressed those concerns which the Skinners had brought to their attention. Although Amax acknowledged a deteriorating relationship with the Skinners it invited continued dialogue to improve their operations wherever possible.

2.4.3 Views Of The Board

The Board is convinced that the previous operations of Amax have had a significant, negative impact on the mental and possibly the physical health of the Skinner family. The Board does not believe that the actions of Amax have been adequate to reduce the impact of their operations on this family to acceptable levels. Rather, Amax has permitted its relationship with the Skinner family to deteriorate to the point where the Board has significant concerns that a working relationship can ever be established again.

The Board accepts that the stress levels experienced by the family are real and that they are unlikely to be diminished without significant change. Further, the Board is not convinced that the proposals set out by Amax to modify their operating procedures are adequate to address the Skinners' concerns. The Board believes Amax has been particularly insensitive in appreciating the effect that the oil field activity surrounding the Skinners' homes and businesses has had on their lives.

The Board also has very serious concerns regarding the suggestion by Amax that when the Skinners had exercised their rights as landowners to request a hearing, that they may have become liable for lost opportunity costs incurred by the company. An important part of the Board's legislative mandate is to ensure that energy development is carried out in the public interest. A significant aspect of that mandate is the right for any member of the public who has a reasonable belief that they may be negatively affected to request a public hearing and to have the Board consider those concerns.

2.5 Company/Landowner Communications

2.5.1 Views Of The Skinners

The Skinners submitted that they were concerned with the type and quality of information provided them during their negotiations with Ladd. One such concern was the manner in which the approval for the 10-16 Dina battery was obtained. The Skinners noted that Ladd informed them that the proposed location was the most suitable for the battery. It was an extension of an existing surface lease for a Sparky oil well, and a clause of that agreement stated that Amax had the right to build whatever facilities it required, including a battery, for its operations. At the time of negotiations, the Skinners noted that they were not aware of their rights as a surface owner afforded them by the Acts and Regulations administered by the ERCB and were under the impression that they had no right to have input into the battery location. In addition, the Skinners stated they did not have prior knowledge that the proposed battery would be processing oil from a formation containing H_2S and that such "sour oil production" could have adverse effects on their farming and farm life. The Skinners further stated that neither representatives from the operator nor its land consultants informed them that the battery would be handling sour solution gas.

With respect to the spacing order, Board Order IW 9011, the Skinners stated that they had not granted permission to Amax to drill the large number of wells possible under the subject order nor was the possible extent of the drilling clearly explained. The Skinners believed that Amax took advantage of the infill well order IW 9011 because its application for the order only specified the need for two wells. They further stated that the surface owner should be advised of his or her rights prior to any drilling operations taking place and should have input into selection of the most appropriate surface location for the well(s). The Skinners submitted that such an increase in activity as could occur if the holding/spacing application was approved or if Board Order IW 9011 was continued would only accelerate and compound the impacts and risks previously mentioned.

2.5.2 Views Of Amax

Amax argued that the Skinners were well aware of their rights with respect to oil and gas development on their land. It stated that the Skinners were provided copies of ERCB Guide G17-2, "Wellsite Selection and the Surface Owner", and had on occasion consulted with their lawyer on surface rights matters.

Amax submitted that it was concerned about the allegations made by the Skinners and viewed the section 42 review application as a challenge to the Company's reputation within the community. It further submitted that its relationship with the landowners has continued over the past 22 years and has been a relationship of mutual benefit and respect. Amax noted the landowners had been active participants in the oil operation by providing contract services such as road clearing, towing and surface reclamation assistance.

With respect to the 10-16 battery, Amax stated its location was decided after having regard for the area topography, operational logistics and impact on the surface area in the vicinity of the battery. The 10-16 battery was located in full compliance with the Board's guidelines at that time, and exceeds the current minimum surface facility spacing requirements. Amax stated that during the development of its oil operations, the landowners were kept advised and provided with the appropriate information packages. These summarized the landowners rights and procedures to be followed in case of disagreement. Amax stated that it had knowledge that on at least one prior occasion, the landowners had used the services of legal counsel to assist them in negotiations. Consequently, the assumption was made that the Skinners were sophisticated landowners and fully aware of options available to them in both site selection and related operations.

Amax said it is a responsible operator with a good operation and in its opinion there is no conclusive evidence which links its oil field operations to the problems cited by the landowners. In its opinion the two industries could coexist and it views the section 42 application as having no basis and serving only to further delay it from proceeding with its development.

2.5.3 Views Of The Board

The Board notes that the Amax Dina oil development in Section 16 is operating under a number of orders, approvals and permits previously identified in Section 1.1 of this report. The Oil and Gas Conservation Act, the Pipeline Act and the Oil and Gas Conservation Regulations require an operator to obtain approval from the Board through an application process prior to drilling a well, constructing production or related facilities such as batteries and pipelines or implementing a change in well spacing. The regulatory requirements for each application type is contained in the appropriate legislation and in each instance requires notification to the surface owner. Upon notification of affected parties and in the absence of objections, the application is approved and the appropriate order, approval or permit is issued.

A reasonably good and long standing working relationship between the Skinners and the energy industry on Section 16 was evident before 1987. Drilling prior to 1987 was on larger spacing units and production was largely Sparky oil that would not be as likely to create the same risks or concern for the Skinners. It would appear that any disagreements between agriculture and energy development on Section 16 prior to 1987 were mutually addressed. The Board accepts that rudimentary knowledge of legal rights and lease agreements were in place between the parties but is not convinced that the Skinners had a full opportunity to understand those rights.

It appears clear that the nature and scale of operations changed dramatically in 1987 to a sour oil operation with intense drilling. This compounded the environmental and social impacts on the farm and its residents. The Board accepts Amax's contention that literature outlining the legal recourse to object to the operation was supplied but also believes that minimal standards were adopted in siting the facilities and questionable public consultation took place. The Board accepts the Skinners' contention that they were unaware of the dramatic change in operation being proposed to the existing energy industry development on their land. The Board also believes the Skinners were within their rights to raise questions about the appropriate location of the 10-16 battery, notwithstanding the existing surface lease for that site. The Board cannot totally excuse the lack of attention that may have been given by the Skinners to the new leases requested by Amax, particularly when some legal advise was obtained at the time. The Board believes, however, that a meaningful consultative process requires energy companies to be forthright in their intent and places the largest obligation on the energy company to ensure effective communication occurs. The Board also believes its guidelines place some obligation on energy firms to recognize the social impact their operation can have on the residents in proximity to their facilities. The Board places the same obligation on companies acting as agents for an oil company. It does not believe that lease negotiations and legal consent to add facilities in this instance were necessarily carried out in that spirit.

The Board believes that at the time of the hearing all the facilities had the proper approvals and the approvals were in good standing. However, the Board recognizes there is considerable disagreement between the parties concerning negotiations and the sequence of events leading to the issuance of Board Order IW 9011, the approval of a satellite battery facility and wells in Lsd 10-16 and the approval of the 10-16 battery. The Board also notes there is a wide divergence of views between the respective parties concerning Amax's operations and the perceived impacts.

3. APPLICATIONS BY AMAX

In considering the Amax applications for well licences, additional satellite production facilities, pipelines, and holding/spacing, including some modification to the 10-16 battery, the Board believes the issues are the need for the wells and related facilities, and the impact of those additions.

3.1 Well Licence Applications

3.1.1 Need

3.1.1.1 Views Of Amax

Amax submitted that it held the rights to explore for and recover any hydrocarbons underlying Section 16 by virtue of Crown Petroleum and Natural Gas Lease Number 14220. It stated that its rights and the nature of the Dina reservoir, in particular the water coning that limits the drainage area of a well (Section 3.4.1) established a need for the 16 proposed wells and that any benefits from the proposed wells would accrue to itself, its partners, the local economy and the Province of Alberta.

3.1.1.2 Views Of The Skinners

The Skinners did not object to the rights of Amax. They did dispute the need for and the surface locations of the wells and argued that the rights of the surface owner should not be disregarded or curtailed. They argued that it was not necessary to have wells every 75 m as indicated in Amax's holding/spacing application and thus there is no need for all of the proposed wells.

3.1.1.3 Views Of The Board

The Board accepts that Amax has the right to explore for its minerals and that there would be benefits to many parties including the Province of Alberta; however, that right must be considered in terms of the economic, social and environmental impact. The Board notes that while the Skinners disputed the need for the wells they did not present an argument to dispute Amax's description of the Dina reservoir. The Board accepts Amax's argument that water coning limits the drainage areas of the wells. The Board is satisfied that, if the wells can be developed and operated with acceptable environmental and social impacts, there is a need for the wells described in the Amax application in order to maximize the recovery of the oil resource.

3.1.2 Location And Impact Of The Proposed Wells

3.1.2.1 Views Of Amax

Amax submitted that the proposed well locations (Figure 3) were selected having regard for the affects on the Skinners, the dairy operation and the environment. The selected well surface locations were further influenced by topography and the technical limitations of drilling the wells directionally.

Amax submitted that its proposed well surface locations would cause minimal land disturbance. This would be achieved by using existing well locations and by drilling the proposed wells from multiple well pads. The wells would be drilled from five existing surface locations and only an additional 1.5 ha of land would be required to drill all 16 wells.

Amax submitted that the maximum horizontal displacement possible for drilling directional wells to the Dina on Section 16 would be 350 to 400 m. Displacements greater than this would result in unacceptable increases in the costs of drilling and operating the wells, well operation problems and frequency of well servicing. The maximum displacement of the wells Amax has drilled to date is 170 m, while the maximum displacement of the proposed wells would be 290 m.

Amax stated that because of its proposed infill well program, the bottom hole locations would be restricted. The infill program and reservoir characteristics are discussed in greater detail in Section 3.4.2.

Amax submitted that it had also considered horizontal drilling technology as an alternative to directional and vertical wells. This was discounted because of technical problems associated with a horizontal well in the Dina reservoir. Production rates along the horizontal section of the well would be greater at the initial portion and less at the end of the wellbore rather than even rates along the length of the horizontal section. This results in greater draw-down and more rapid water breakthrough (coning) at the heel of the wellbore thus severely reducing efficiency. Amax referenced a published paper that analyzed and compared some horizontal well performance with vertical wells. The publication concluded that horizontal well recoveries were less than that achieved with vertical wells. Furthermore, a horizontal well did not seem to delay water coning as much as expected and cost approximately two to two and one-half times more than a directionally drilled well. It did agree that a horizontal well surface location could be at a greater distance from the farm than the proposed pad locations.

Amax also considered slant hole drilling technology and stated that a slant hole in this pool could handle a horizontal displacement up to 600 m. It believed that the proposed wells could be drilled with a slant hole rig without an adverse affect on drilling and production of the wells. The poor availability and higher costs of slant drilling and service rigs was of concern. Amax's preference, if greater separation distances than those proposed were required, would be to drill the wells directionally, using a higher kick-off point and drilling angle. This could be achieved by using more sophisticated drilling technology. This approach would increase the drilling and servicing costs of the wells. The resulting increase in wellbore angle could be handled by screw pumps without a substantial increase in rod and tubing wear.

Amax stated that it had established a minimum separation distance of 150 m from the perimeter of the farm to its proposed drilling locations. This distance is greater than the minimum separation distance of 100 m established by the Regulations and it believed that the locations would be sufficiently removed so as not to cause any undue impacts on the Skinner farm.

Amax considered the proposal put forth by the Skinners whereby any further drilling would be restricted to particular areas separated from the farm at distances greater than Amax's minimum separation distance. It stated that if it were a requirement, it could accept some of the restrictions as some of the zones established by the Skinners would still allow it to drill within its maximum horizontal displacement. Amax did not indicate which locations could be moved.

3.1.2.2 Views Of The Skinners

The Skinners submitted that the drilling and operation of the 16 proposed wells would only compound the problems they experience from the existing wells and facilities. They believed that the locations were chosen without adequate regard to potential impacts on the dairy, the families or the environment. Rather, they were chosen with regard for Amax's desired technical requirements for directional drilling. The Skinners argued that additional wells in proximity to the farm would mean additional crews, noise, emissions, traffic, dust, stress on the family and the dairy herd, more frequent service operations and impacts to their water wells and aquifers. They believed that Amax's track record showed that it could not operate its wells diligently without causing the impacts described above and that this should be given considerable weight in the Board's decision on the proposed well locations.

The Skinners stated that in their opinion the minimum separation distances set out in the Regulations are not applicable to all situations. A 100 m separation distance from a well to a surface improvement such as a grain elevator may be appropriate but 100 m may be an entirely inappropriate separation distance to a residence or some industries. They contended that the minimum Regulation separation distance and the separation distance suggested by Amax are inadequate in this case and would not ensure acceptable protection to the dairy.

The Skinners stated that in order to reduce impacts to an acceptable level, future drilling operations should be limited to areas that are outside of the Skinner bowl. They proposed three zones (Figure 3)[2]. The Skinners requested that existing wells within the red zone be abandoned over the next two years. The yellow zone, in their view would provide an appropriate separation distance around the farmyard and residences. They requested that while the existing wells could remain on production, no further drilling be allowed within the yellow zone. They stated that locations existed outside of the yellow zone, in the white zone, that would still provide for drilling to the bottom-hole locations of the proposed wells within the maximum possible horizonal displacement submitted by Amax. This proposal is more fully described in Section 4.1.1.

3.1.2.3 Views Of The Board

The Board notes that historically, drilling and production operations in and around the Skinner farmstead have caused significant problems for the Skinner dairy and families. The Board agrees with the Skinners that impacts such as occurred from past drilling and production operations are not acceptable. The Board must consider whether the wells proposed by Amax could be drilled and operated without a repeat of past problems and if potential impacts from the proposed wells could be reduced to an acceptable level.

The Board considers the physical topography of the land, the drilling concentration and the density of agricultural and social activity on this land to be unique. The drilling and operation of Amax's proposed wells would considerably increase the activity that presently occurs in the bowl area. The Board foresees that many impacts such as noise, dust and traffic would increase proportionally. The Board believes these impacts would heighten the stress currently experienced by the Skinners and the Board does not accept Amax's contention that there would not be any undue impacts from the proposed wells. Furthermore, given the current level of activity, when combined with the proposed wells, the Board does not believe that the impacts could be reduced to an acceptable level.

---

[2] Figure 3 has been prepared from Exhibit 83 which used three colours–red, yellow and white, to outline the zones.

The Board agrees with the Skinners that the standard separation distance established by Regulation 2.110(1) is not appropriate for all situations. The Board believes that the Regulation reserves a discretion for the Board to determine appropriate separation distances in any particular case. While the separation distance of 150 m requested by Amax creates a greater buffer, the proposed wells are still in proximity to the Skinner farmstead and largely within the Skinner bowl. The Board sees merit in the proposal put forth by the Skinners for a restricted area around the Skinner bowl. It generally supports the proposed separation distance for Dina wells and facilities, although the Board could support a reduced restricted area if the parties agreed. The Board notes that all of the proposed wells could be drilled outside of the Skinners' yellow zone and still maintain a horizontal displacement of less than 400 m.

The Board believes that an increase in the separation distance for the drilling and operation of the proposed wells, such as set forth above, would decrease the impacts associated with the wells on the dairy and families. Most of the proposed locations would be removed from the Skinner bowl entirely. Existing well locations around the perimeter of the Skinner restricted area represent viable alternatives to the locations proposed by Amax and would allow Amax to continue its program of minimal land disturbance through pad drilling. If some of the proposed wells were denied, the Board would expect Amax to consider alternative surface locations with particular attention to maintaining a maximum distance between the proposed wells and the Skinner farm.

The Board agrees with Amax that a horizontal well may not be a viable alternative to drilling vertical or directional wells. On the basis of present horizontal well experience, it accepts the technical reasons presented by Amax for discounting a horizontal well at this time.

The Board accepts that slant hole wells may not be a viable option for increasing separation distances because of the questionable availability of rigs and increased costs. It also notes that it would be Amax's preference to utilize more sophisticated directional drilling technology rather than slant hole technology in order to increase horizontal displacement.

Notwithstanding these limitations, the Board expects Amax will use the most appropriate technology to meet the separation limits imposed.

3.2 Satellite Production Facility

3.2.1 Views Of Amax

Amax stated that it requires an additional satellite facility to the one currently operating at 10-16 to test wells that are manifolded at an existing field header on the same location. The additional satellite would be located at 10D-16 and would eliminate the installation of a line loop from the 10D-16 field header to the 10-16 battery. Amax stated that the test separator installed at the satellite would have high/low pressure and high liquid level shut-downs. Further, an instrument air compressor would eliminate the use of sour solution gas as instrument air.

3.2.2 Views Of The Skinners

The Skinners contended that historically Amax has shown it cannot operate the existing wells, satellites and battery facilities without the risk of escape of fugitive emissions, the risk of fire and explosion, the risk of polluting surface and groundwater and the risk of polluting soil. The Skinners argued that further expansion of the Amax facilities will only add to the risks involved in operating those facilities.

3.2.3 Views Of The Board

The Board accepts that if additional wells are drilled by Amax, then new satellite facilities will be required. While the Board believes some improvements in the operating system and diligence by the operator should improve the performance above that experienced in the past the Board is not sufficiently convinced that such improvements would totally prevent a repeat of many of the incidents experienced since 1987. In this case, the final location of the satellite will be dependent on the surface location of other facilities including both the 10-16 battery and the various wells.

3.3 Pipelines Applications

3.3.1 Views Of Amax

Amax submitted that if the Board approved the 16 proposed well locations it would require the proposed pipelines in order to accommodate proration testing and treating of oil well effluent from those wells that were successful. It stated that landowner consent had not been obtained for the location of the pipelines. It stated that as the H_2S content of the well effluent was below five mole per cent the pipelines would not be required to meet sour service standards. It stated that all its Dina pipelines are installed with an internal liner that retards corrosion and it utilizes corrosion coupons and cathodic protection to monitor and prevent corrosion.

3.3.2 Views Of The Skinners

The Skinners did not dispute the need for the pipelines and stated that if the proposed wells were drilled and successful, pipelines would be preferable to trucking fluids from the wells to the battery. They did not provide comments with respect to the locations of the pipelines and believed that if wells were drilled it followed that the wells would be pipelined.

3.3.3 Views Of The Board

The Board believes that if the proposed wells were drilled and successful, there would be a need for the proposed pipelines. It agrees with the parties that pipelining well effluent is preferable to trucking the effluent because of the adverse impacts associated with trucking, particularly noise, dust, safety and the potential for odours. The Board considers the measures Amax proposes for monitoring and minimizing corrosion of the pipelines to be appropriate and if the proposed wells are approved the Board would approve the pipeline applications.

3.4 Production Facilities And Holding/Spacing Application

3.4.1 Technical Suitability Of The 10-16 Battery Modifications

3.4.1.1 Views Of Amax

Amax submitted that with the proposed expansion it will use as much of the existing facilities as possible. Only three new field satellites and one satellite expansion would be required within the field to accommodate the gathering and testing of the wells. The total 10-16 battery fluid capacity is currently 2500 m^3/d. Since fluid flows are estimated to rise to 2500 m^3/d with the additional wells, expansion of the water handling facilities by adding a second free water knockout vessel and water settling tank would be required. By operating at less than full capacity, Amax contended that this would reduce the chance of upset and potential risk of emissions. Amax submitted that most of the oil would be recovered after water breakthrough had occurred and that eventual oil production would depend on how efficiently the water is handled. Amax stated that installing additional water capacity early in the project would assure maximum recovery.

Amax submitted no changes would be required to the oil handling facilities at the 10-16 battery in order to accommodate production from the proposed wells.

3.4.1.2 Views Of The Skinners

The Skinners objected to any further expansion of the 10-16 battery since this would only increase the risks involved in the operation of that facility. These risks are presented throughout this report.

3.4.1.3 Views Of The Board

The Board agrees that, should the scheme as proposed by Amax be approved, then expansion of the fluid handling systems of the 10-16 battery would be necessary. Other concerns of the Board with the 10-16 battery configuration and operation are set out in Section 2.2.1.3.

3.4.2 Proposed Expansion And Holding/Spacing Application

3.4.2.1 Views Of Amax

Amax submitted that the Dina is typically a fluvial sandstone deposited unconformably on the Devonian carbonates. Hydrocarbon trapping mechanisms are controlled by a combination of stratigraphic and structural components that may be partially controlled by an underlying Devonian salt formation. Primary reservoir energy is supplied by a strong, active underlying water drive.

Amax further submitted that production from the wells located in the thicker portions of the reservoir is characterized by high production rates. However, due to the difference in viscosity between the oil and water a viscous fingering effect creates a water cone. Water breakthrough usually occurs after a short period of clean oil production. Oil production declines harmonically thereafter. Amax said the water cone reduces the drainage area and the amount of recoverable oil for each well. Consequently, to achieve higher recoveries, additional wellbores are required.

Amax initiated a pilot project to evaluate infill drilling under Board Order No. IW 9011, in Lsd 10-16. This location was chosen because it was drilled out on four-ha (10-acre) spacing and production had obtained a 90 per cent water cut. The first well was drilled in 10D-16 and placed on production in March 1990. Initial production was 43 m^3/d of oil with no water, proving that recoverable oil exists between existing "watered out" wells in the pool.

Amax submitted that previous studies indicated a well drains a radius between 60 to 75 m, and believed a 100 m subsurface-interwell distance would be satisfactory. The shorter inter-well distances do not consider the heterogeneity vertically and horizontally across the reservoir. It chose potential well locations utilizing a 100 m inter-well distance but requested a 75 m distance to avoid conflict with some existing wells.

Based on volumetric calculations Amax estimated the Dina in the area of application has an oil in place volume of 3.2 x 10^6m^3, of which 27 per cent or 868 x 10^3m^3 is recoverable. Amax estimated that the proposed expansion would result in an incremental recovery of 496 x 10^3m^3 oil over the present development.

Due to the limited drainage areas of the Dina wells, Amax proposes to eventually drill an additional 55 wells to complete its project. Daily fluid production would remain relatively constant and below the 10-16 battery capacity of 2500 m^3/d. Amax stated that with the additional wells planned for Section 16, there may be a total of 100 rig-days per year required for service operations of which approximately 30 would occur in the vicinity of the Skinner bowl.

Finally, Amax submitted that its proposed development would have significant economic benefits. It estimated that the cost of the wells and facilities would be 14 million dollars. Royalties paid to the Province would total 9.2 million dollars and 1.5 million dollars would be paid to the Skinners for lease rentals over the project life. It further estimated that the Town of Provost and the municipalities of Provost and Wainwright would receive approximately 14 million dollars through the life of the project.

3.4.2.2 Views Of The Skinners

The Skinners recognized that the oil industry is important to the local economy and the Province. They realize that oil is present under lands to which they own the surface rights and agree that Amax has the right and should be allowed to produce the hydrocarbons. However, the Skinners questioned the need for such a large number of wells located so close together and suggested that Amax may be trying to capture the oil more quickly in order to benefit from government incentive programs.

The Skinners said they did not oppose the Dina development and were not trying to prevent Amax from drilling, however, they are concerned about the potential for the increasing impacts arising from such a large development. The basis for their concerns and subsequent opposition to the Dina development arise from the impacts experienced from Amax's existing operations, previously discussed under Section 2.

The Skinners stated they were not prepared to give their consent to the expanded development until the conditions outlined in their development proposal outlined in Section 4.1.1 and Figure 3 are met. The Skinners emphasized that the two industries must coexist and participants in the industries must recognize and respect the rights of each other.

3.4.2.3 Views Of The Board

The Board believes that the success of both Alberta's agriculture and energy industries is fundamental to the continuing economic well being of the Province. Neither industry can automatically be considered paramount when decisions beneficial to one will have negative effects on the other. In every case, the overall public good must be carefully weighed. Equally important is the need to ensure that individual rights are protected, as a key component of protecting the broader public interest. The Board believes that the extraction of the Province's mineral wealth must be carried out in a manner which ensures that the rights of the surface owner are respected. These include the right of a landowner to a reasonably safe and healthy environment, and to an opportunity to earn a living from that land. Before the Board can approve an energy development, it must be convinced that the applicant's proposal will protect these rights. In this case, the Board's concerns stem from both the previous actions of Amax and from the intensity and proximity of new development to the Skinners.

The Board believes that the Amax estimate of 100-rig days per year for servicing operations of an expanded operation is an optimistic view. Combined with the level of new drilling activity proposed it would be reasonable to assume that drilling/service rig operation on or around the Skinner farm could be virtually constant for the next two to three years. The majority of this development (i.e. the first 16 wells) would all be located in areas surrounding the farmstead. Even with the drilling program suggested by Amax, including use of "low noise" rigs and restriction of noisier drilling operations to daylight hours, there is no question that these activities have a high potential to significantly affect the quality of the life of the Skinners, and possibly their dairy operation as well.

The Board notes that during the hearing Amax expanded somewhat on its proposal (Appendix B) and indicated that it would be willing to consider further modifications based on proposals made by the Skinner family (Section 4.1.1). Amax did not, however, formally amend its application at the hearing, nor has it submitted an amendment to the Board.

The Board believes the concurrent development of an existing oil pool in proximity to a large established agricultural activity in this instance is unique for a number of reasons. The most significant of these is the impact that the need for intense drilling and the related activity will have on a confined geographic area competing for multiple land uses and used by a significant number of people.

The Board notes the substantial reserves projected in this pool and believes the development is economically viable and would serve the public interest.

The Board is satisfied that Amax's geological and reservoir description is reasonable and the production characteristics displayed by its wells are typical of Dina wells. The Board agrees that once a well cones water, the drainage radius of the well is limited. Consequently, to achieve better oil recoveries, additional wellbores are required. The Board is of the view that the estimate of recoverable oil is reasonable for the subject area. The Board notes that the Dina in the Hayter and Provost areas is being developed predominately on four-ha (ten-acre) DSU's with an equivalent of two-ha (five-acre) DSU's being achieved through the establishment of holding and miscellaneous spacing orders. Such development options are intended to provide sufficient flexibility to the operator to maximize recovery. Drilling spacing unit provisions of this nature will result in the drilling of a large number of wells which significantly increases the potential surface impact normally associated with oilfield operations. The Board is satisfied that the interwell spacing of 75 m in the producing formation proposed by Amax represents a sound and reasonable approach to drain the reserves. The Board also accepts the development profile proposed by Amax as orderly recovery.

The Board believes, however, that the development of a high well density play such as proposed by Amax, requires a different approach than the more traditional oil pool. Unfortunately, impacts on nearby landowners such as the Skinners can become overwhelming due to the intensity of the development. Matters such as lease access, traffic control, dust control, pollution control and well servicing operations have significant impact and must be given a higher priority in the planning process. The fact that the oil contains H_2S also has a strong bearing on how the development is carried out. In this instance the impact was compounded by the proximity of dairy and oil production facilities.

The Skinner dairy farm is a well established, sizeable operation that essentially occupies most adult members of four families. The Amax proposal in turn is competing for land in proximity to that agricultural and domestic activity. The nature of the Skinner dairy business requires the constant attention by the families. The landscape surrounding their homes and dairy operation offered a sense of seclusion and privacy in the absence of oil activity. Limited intrusions by the energy industry up to 1987 were accepted in a spirit of their mutual right to exist and develop individual interests. The Board believes that the level of activity and oil well density since 1987 was seen as an unacceptable intrusion.

While the Board believes its minimum separation guidelines for industrial and agricultural operation are reasonable for a situation involving limited facilities, the proposal by Amax requires a more comprehensive approach.

The most intrusive of the existing facilities on the Skinner farm is the 10-16 battery. Its present location on the hill represents a constant reminder to the families of a real or perceived danger and a potential source of environmental insult. The Board does not believe the present situation is acceptable in the long run nor one that will allow both operations to coexist and flourish. Given the proximity of their operations the Board expects that the proposed expansion by Amax would perpetuate an unacceptable situation in the long term and should not be approved.

The Board has concluded that developments such as those proposed by Amax must be planned on a total project basis, incorporating all aspects of the development such as well site (pad) locations, access routes and production facilities. Not only must this plan have regard for the requirements of the Provincial Acts and Regulations but also for the cumulative impact on surface use and on the occupants of the land and the other operations in proximity to the oil and gas activity.

The Board is satisfied that Amax's proposed development has positive economic benefits for the local area and the Province and, subject to some agreeable arrangement with this equally intense agricultural activity, it should be developed. The Board is not convinced, however, that the benefits from this project outweigh the negative impacts that would result from the development as presently proposed by Amax. The intensity of each of the respective industry's activity makes it difficult in this situation to find mutually satisfactory compromises.

4 ACTIONS TO ADDRESS IMPACTS

4.1 The Skinner Proposal

4.1.1 Views Of The Skinners

While the Skinner families would prefer oil and gas activity be removed from their home quarter they acknowledged this is an unreasonable expectation. In the absence of that option the Skinners offered their compromise position. They submitted that it is important to establish a "safety zone" between the dairy and oil industry activities. This would provide a comfort zone so that the local inhabitants do not have to constantly worry about mishaps occurring at the production facilities and in the long term provide the assurances required to continue their dairy operation and provide Amax with an opportunity to produce its oil.

The Skinners stated that they divided Section 16 into three separate zones designated red, yellow and white (Figure 3) depicting areas of varying levels of acceptable oilfield development. The red zone would, in their plan, be reserved solely for agricultural purposes because it contains the residences, the dairy operations and land set aside for future expansion of their operations. The red zone was largely selected to contour the high points of land surrounding the farm. In this area, there are presently nine wells and the Skinners requested that these wells be phased out of production and abandoned within two years. The surface leases would then be reclaimed and surface-lease agreements terminated.

In the yellow zone all existing wells would be permitted to continue to operate with Amax determining the longevity of the well's life. Amax would have to provide a high standard of maintenance and servicing of these wells so as to avoid impacting the dairy operations. No new wells would be permitted in this area. In general this would imply a minimum separation distance approximately 200 m from the nearest farm building.

New development drilling would only be permitted from the white zone. No restrictions would be placed on drilling in this area other than the best technology should be used to maximize the recovery of oil, while minimizing impacts and the inconvenience to the landowner.

The Skinners do not believe the existing separation distance Regulations were written with the type of oilfield development proposed by Amax in mind. In their opinion, the 100 m separation distance is not adequate in this case when the intensity of the development is considered. They feel the requirement is a minimum and should not prevent a greater distance should circumstances dictate. They believe that a larger separation distance must be established to preserve their quality of life.

With respect to the 10-16 Dina battery, the Skinners submitted that it should be moved to Lsd 4 of 16. From their perspective, this would be a good location because Amax already has an existing lease which is close to power, natural gas and a municipal road for ease of access. The most important advantage of the location is the separation distance it provides between the battery and the dairy operations. In addition, the terrain will assist in minimizing the effect of spills and other emissions previously associated with the operation of the battery. Remaining at the current 10-16 battery site would be the existing water disposal facilities, satellite test facilities and a flare stack to be used in emergency situations only. No storage of any liquids at this site would be permitted.

The Skinners believe the best way of handling the sour solution gas is to re-inject it into its zone of origin. This would eliminate the immediate and potential problems associated with handling and flaring the sour gas. Sweet gas should be used as fuel for the battery.

The Skinners said that to operate a successful dairy, they must have access to a good supply of quality water; consequently, they are concerned with both the surface and groundwater resources. They argued that their water must be tested for contaminants and a study conducted to establish groundwater flow patterns. New oil wells must have surface casing set at 25 m below the Ribstone Creek. Existing wells must have the integrity of the casing cement job verified and the extent of casing corrosion must be determined for both the surface and production casing strings. Wells no longer in service or capable of service should be abandoned immediately by filling the wellbore with cement from total depth to surface.

4.1.2 Views Of Amax

Amax considered the proposal put forth by the Skinners and believed that it could accommodate some of the requests made in the proposal. It did, however, have reservations regarding the relocation of the 10-16 battery and some of the proposed wells.

Amax submitted that it does not propose any new drilling within the Skinners' designated red zone and it recognized that within the yellow zone there is a need to move some of the proposed locations farther from the farm area. It said that it would make every effort to keep its locations outside of this zone and would work with the Skinners to accomplish this. Amax stated that the only problem area would be along the north-eastern boundary of Section 16. Complying with the Skinners' proposal for the yellow zone would necessitate moving some locations into Section 21 which would require negotiations with, and consent from that surface owner.

Amax stated that it was reluctant to agree to a two year limit on operations within the Skinner red zone because of the type of completion profiles exhibited by the Dina wells. While it agrees that a substantial volume of oil has been produced from the four wells on Pad 1 in the past two years, it indicated that the oil rates are not proportional to time. Consequently, the wells would quite likely produce for much longer than two years.

With respect to other existing wells within the Skinners' zones, Amax submitted that it has made changes to some and proposes work on others. Two wells were shut-in because of noise complaints that resulted from the hydraulic drives on those wells. Amax has a work-over operation planned for the 15B-16 well to try to shut-off water production. It stated that it does not have plans to recomplete surplus Dina wells for a Sparky waterflood.

Amax submitted that the most difficult item in the Skinner proposal to address is the relocation of the 10-16 battery. It stated that the economics of the prospect have changed considerably due to the length and cost of the hearing, and due to the likelihood of no significant number of wells being drilled prior to March of 1993 and therefore, its inability to take full advantage of the royalty holiday program currently in-place. After considering these impacts on the project economics, it estimated that the after-tax value of the project would be reduced by nearly 40 per cent. The relocation of the battery would place a very severe financial hardship on the company and put it in the position of having to re-evaluate the project.

Amax submitted that the cost of relocating the battery would be approximately 3.8 million dollars. It did not believe that relocation of the 10-16 battery is warranted because the changes it has made to the battery and the proposals in Appendix B would ensure minimal impact to the Skinners and the dairy. It did agree that measures such as relocation of the flare to a remote site or the use of an incinerator are possibilities that warrant consideration and would be prudent steps to take in order to reduce emissions.

Amax submitted certain steps to be taken in order to protect groundwater in Section 16. It proposed to monitor groundwater around the Sparky battery and the remote sump. It also considered a monitoring well that would be located in the valley near the Sparky battery. The Ribstone Creek aquifer could be monitored from an existing water well although Amax was uncertain if this would yield any new information. It stated that surface casing on any future wells would be set to a depth of 130 m and in its opinion the current practice of cementing the surface and production casing strings to surface was adequate protection. Lastly, Amax said that its well abandonment practices would protect groundwater.

4.2 Board Direction

The Board has been asked to address two issues. The first is to consider, under section 42 of the Energy Resources Conservation Act, the impacts of the Amax operations on Section 16 and to determine whether, in the Board's view, these impacts are acceptable. The second issue is to determine whether further expansion of the Amax operations on Section 16 would be consistent with the public interest.

It is clear from the evidence that past oilfield operations on Section 16 have not been without significant recurring problems. As noted earlier, the potential effects of these operational difficulties have been exacerbated by their proximity to the Skinner family farm and by the type and size of their agricultural operation. Amax has apparently dealt with a number of these problems. However, they have tended to be reactive, responding only to a complaint or serious problems, rather than proactive. Although Amax has made improvements in its operations and has indicated it intends to make more, the Board continues to have serious reservations regarding the company's long-term commitment to carrying out oilfield development in Section 16 in a manner consistent with their proximity to the Skinner family residences and the dairy farm.

With regard to existing wells, satellite facilities and pipelines on Section 16, the Board is not convinced that recision or significant amendment of these approvals is required. The Board will require Amax to ensure those facilities are maintained and upgraded in some cases. In particular, the Board will expect Amax to improve well site fencing and weed control, particularly in the calf pasture. The Board agrees that the nine Dina wells in the identified red zone confine agricultural activity and the land should be made available to the Skinners within a reasonable time period. As these wells reach the end of their economic life the Board will expect them to be abandoned and the surface reclaimed as quickly as practical. In any event, the wells should be abandoned and surface reclamation initiated within four years after the release of this decision.

The Board considers the present surface casing requirements adequate, however, it would accept Amax's proposal to set it at a depth of 130 m as an extra precaution. Full length cementing of both the surface casing and production casing is adequate protection of water aquifers. Bond logs are not necessary to assess the cement jobs unless monitoring of cement returns to surface indicates unsuccessful placement of the cement.

Plugging or isolating the producing section of a cased wellbore with cement, displacing the cased wellbore fluids with inhibited water and capping the well below ground level with a welded steel plate or cement is standard acceptable abandonment procedure and meets present Board requirements.

The Board directs that the condition of the existing sump in Lsd 9-16 be assessed as to contents, suitability of its location and construction, future use, need for reclamation and fencing. It shall not be used for invert or similar needs. The Board's staff will take part in the assessment.

The Board believes that the frequency of spill events from both Sparky and Dina operations in Section 16 to be excessive. The Board will require Amax to prepare a program to further reduce spill frequency and to confirm future surface remediation programs.

While the Board believes the proposed well completion techniques are adequate to protect water quality, it recognizes the critical nature of that supply. The Board will require Amax to set up a suitable monitoring program to detect any long-term impacts on water from its operations.

It is expected that Amax's air monitoring programs, including the environmental check list program, for Section 16 will be continued. The Board would also expect Amax to address noise issues in any future monitoring.

With regard to the 10-16 battery, the Board accepts that Amax has made many improvements to this facility, and has committed to others such as redesign of the stacks. Other options, such as addition of a remote flare or re-injection of solution gas, would likely further improve the safety and reduce the environmental impacts of the facility. Given the location relative to the farming operation the Board is not convinced, however, that these modifications would adequately reduce the potential impact on the Skinners' quality of life and allow the long-term coexistence of the agricultural and energy industries on Section 16 without recurring problems. The Board is of the view that whether the threat is real or not, the Skinners now consider the 10-16 battery to represent a totally unacceptable risk to their health, safety, and livelihood. The Board can appreciate the circumstances which led the Skinners, based on their previous experience, to this belief and the long-term operation of the 10-16 battery would only add to the risk that future upset could reoccur.

In assessing the public interest, the Board is required to weigh the positions of landowners and an energy company as to whether the negative effects of the development on the surface owner are outweighed by the overall benefits accruing to the people of Alberta. There is no question that some energy developments will intrude upon the quality of life of nearby residents, particularly in some rural environments. In this case, the Board is not convinced that the 10-16 battery, in its present configuration and current loading, represents a clear risk to the health of the Skinners' dairy cattle. The Board does believe, however, that the location of the 10-16 battery will interfere significantly with the Skinner family's quality of life, and their emotional well being and therefore may impinge on their ability to earn their livelihood from the dairy. The Board agrees with the Skinners that the separation distance requirements are intended to reflect minimum distances that may not apply to the type of oilfield operations proposed for Section 16. The Board is convinced that increased separation distances between the two operations are essential for the long-term development of both industries on Section 16.

The Board believes that the relationship between intense agricultural and oil development on the Skinner land is particularly unique. The proposed expansion would result in the operation and servicing of some 92 wells and related facilities on Section 16. Given that intensity of oil activity, the level of agricultural activity and nature of human activity in the area, the Board does not believe that it is appropriate to have the 10-16 battery in its present location. The Board recognizes that the relocation of the 10-16 battery represents a substantial economic penalty to Amax but believes that increased separation offers the only real option to allow further development of the pool. Under suitable fiscal incentives, this alternative still provides a sizeable economic benefit to Amax and would also be in the public interest. Therefore, the Board intends, under the provisions of section 42 of the Energy Resources Conservation Act, to rescind the approval for the 10-16 battery. To provide for an orderly transition the Board is prepared to allow Amax to continue operation of the 10-16 battery for up to one year beyond the date this decision report is issued, provided the battery continues to be operated in a manner consistent with both the undertakings made by Amax and the requirements of the Board. Furthermore, the Board would also be willing to reconsider this decision should a material change occur in the relationship between the Skinners, their dairy operation, and the Amax operations although the Board would expect any other arrangement to comply with the spirit of this decision. The Board does not intend to order Amax to carry out any modifications to the existing 10-16 battery, but does expect maintenance and operations to be kept at a high level.

The Board recognizes that various options are available to achieve the requisite separation of the agricultural and oil operation. While the Board accepts the Skinner proposal to be a reasonable compromise, closer review and planning may in fact provide revisions that are of greater interest to both parties. The Board believes that only such close consultation will permit the two operations to coexist on Section 16. The Board believes other locations on Section 16 may well be suitable and it would be prepared to consider such an application as part of an overall development scheme for the pool. The Board believes that retention of satellite test facilities at the current 10-16 battery site will be appropriate but this must be specifically considered in the overall facility development plans. If free water knock-out facilities are to be used at this satellite, it must be a closed system and no storage of any liquids will be permitted.

With respect to the Amax well licence applications, the Board does not consider it appropriate to issue the licenses until the relative location of other facilities are established in light of this direction and firm plans are made on all well locations and gathering lines. The unique circumstances of this development, and particularly the potential well density, require that any new developments have appropriate separation distances from the Skinner bowl. The Board notes that the locations proposed by the Skinners appear to be technically feasible, but the Board will expect Amax to address the optimal locations in direct discussions with the landowners.

Since the need for pipeline and satellite approvals hinge on approval of the well licences, the Board is not prepared to grant these at this time. The Board agrees that effective oil recovery from the Dina pool will require more wells for the reasons discussed in Section 3.4.2 of this report. Accordingly, it is prepared to approve the holdings and the applied for spacing orders for Section 16 and the south-east quarter of Section 21, respectively, to provide well location flexibility while maintaining orderly and efficient well distribution. The Board emphasizes that this only confirms that the Board is technically satisfied the minimum well spacing applied for by Amax is necessary to drain the pool. Approval of the holding and spacing orders provides for spacing of the wells within the reservoir. It in no way assures or implies the automatic right to surface locations or production facilities for the desired wells. These must be applied for and approved through the well license, pipeline and production facilities application process. The Board considers it important in this case to address the overall development of the pool, with particular attention to the unique multiple surface use considerations in Section 16, when filing any further well, pipeline and production facility applications.

Notwithstanding that further applications must be filed to provide for the final location of these facilities, and subject to adequate consultation between the Skinners and Amax, these applications should be able to be dealt with in a routine manner and without the further need for a public hearing.

The Board is convinced that goodwill on both sides is necessary to re-establish sufficient trust among the parties in the long run that will allow their respective operations to coexist on Section 16. Amax must recognize its operation represents an inordinate intrusion upon the Skinners, their business and their lifestyle. The Skinners in turn must respect that certain technical and cost limitations imposed on the oil industry may preclude some options that may otherwise be desirable. Health and safety of the families, however, must not be compromised in that arrangement.

To build that trust the Board recommends that Amax consider retaining a neutral facilitator at the outset of its negotiations with the Skinners. In time, the need for such a facilitator may not be necessary as both parties achieve a level of confidence that their respective interests are considered fairly in the development of the oil pool beneath the Skinner farm.

5 DECISION

Having considered the applications by the Skinners and Amax, the Board, for reasons outlined in this report, has decided:

- As to Application 910526 by the Skinners, pursuant to the provisions of section 42 of the Energy Resources Conservation Act,

  a) to allow Amax to continue operation of the 10-16 battery for up to one year beyond the date of Decision D 93-3, provided the battery continues to operate in a manner consistent with both the undertakings made by Amax and the requirements of the Board; Battery Approval No. FS04587 for the 10-16 battery will then be rescinded;

  b) to condition nine Dina wells that are located in the Skinner red zone those being, Well Licence Nos. 0126936, 0126951, 0129290, 0130379, 0143409, 0144248, 0144249, 0144250, and 0144251 so that they will be abandoned and the well site reclamation initiated within four years; no amendments or alterations are made to the other 20 Well Licence Nos. 0036069, 0077707, 0126937, 0126950, 0128313, 0128314, 0128315, 0129291, 0129293, 0130375, 0130376, 0130430, 0130921, 0131797, 0131799, 0131802, 0131803, 0140545, 0143799, and 0144255; and

  c) to permit present satellite production facilities that direct production to the 10-16 battery to remain, however the satellite facilities in the Skinner red zone shall be removed when the 9 wells in that zone are abandoned.

- To deny Amax's Applications 910890 to 910905 inclusive and Application 910790 pursuant to the Oil and Gas Conservation Regulations for well licences and for satellite production facilities respectively, and Application 910972 under the Pipeline Act for pipelines.

- To approve Amax's Application 910289 pursuant to the Oil and Gas Conservation Act and Regulations for holdings and special spacing order for wells drilled or to be drilled within the holdings. Board Orders for that purpose will be issued which will include rescission of Board Order No. IW9011.

DATED at Calgary, Alberta on 2 March 1993.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng. Vice Chairman	B. F. Bietz, Ph.D, P.Biol. Board Member	N. G. Berndtsson, P.Eng. Board Member

APPENDIX A
(Exhibit 17)

MEASURES TAKEN BY AMAX
AT 10-16 BATTERY

1. Relocated access road.
2. Fugitive emission study.
3. Added additional fire fighting equipment.
4. Installed and operate air quality monitor.
5. Studies and preparation to address Application Number 910289.
    - (a) soil study
    - (b) hydrogeological study
    - (c) ambient air quality study
    - (d) inhouse and third party engineering review
    - (e) environmental audit
    - (f) agricultural (dairy) study
6. Installed VRU backup.
7. Replaced all thief hatch assemblies.
8. Changed procedure for thief hatch seal replacement.
9. Replaced flare stack with 60 foot flare stack.
10. Replaced all instrumentation with instrument air or non-discharging controllers.
11. Discontinued trucking of fluids to 10-16 battery.
12. Upgraded VRU at the Sparky 8-16 battery.
13. Replaced VRU lines with plastic pipe.
14. Redesigned, insulated and heated VRU and flare system.
15. Withdrew original Application Number 900435, in favour of present application.
16. Withdrew well licence applications for three wells; D3, D4, D5/10-16.
17. Voluntarily suspended operations at A2, A3, B2, D6/10-16.
18. Replacing all hydraulic drives with electric drives.
19. Suspended operations at wells 15B-16 and 10C-16 due to noise from hydraulic drives and proximity to Skinner residences.
20. Co-op gas used to fuel lineheater.
21. Improved effort and desire on part of operating staff.

APPENDIX B
(Exhibit 25)

AMAX PROPOSAL FOR CONTINUED OPERATION OF BATTERY AND HOLDING DEVELOPMENT

1. All of the changes made to the battery as already discussed will remain in-place.
2. The air quality monitor will remain on Section 16. The environment checklist program with hand-held monitors on site will continue.
3. Groundwater monitoring will continue with freshwater well sampling and the use of the existing observation wells.
4. Progressive Cavity Pumps (screw pumps) will continue to be used to minimize visual impact and noise, reduce space and servicing required for each well. All top drives will be electrically driven direct drives.
5. The existing leases will be used as much as possible to minimize surface impact. Wherever possible, leased land will be returned to use for agriculture purposes.
6. The minimum encroachment distance of 150 m proposed in the Holding Application will be respected. The fencing on Pad No. 1, will be changed to reduce the area required for well operations,and lower area on Pad No. 1, will not be used for further development.
7. The aspen stand that was in between the dairy and the battery will be replanted after permission is received from the landowners to do so. This will provide both a visual and a sound barrier between the dairy and the battery. Amax invites suggestions on landscaping to help further reduce the visual impact of the operations.
8. The project will use available spare capacity in the treater. Major changes to the oil handling facilities are not required.
9. The water handling capacity will increase to meet fluid production requirements. No additional lands will be required for the modifications.
10. The development should proceed after receiving approval from the ERCB. Project completion is expected to be in 1993.
11. Selection of drilling rigs will include a criteria for "low noise" rigs. Drilling around the interveners residence will be limited to one rig. Though drilling activity requires 24 hour operation, wherever possible, "noisy" operations will be restricted to daylight hours.
12. All construction and well servicing activities will be restricted to daylight hours.
13. Well servicing in the area adjacent to the residences will include procedures that minimize any potential for odours.
14. Amax is and will continue to implement advice from expert consultants, including Western Research, Western Oilfield and Farries Engineering. This includes existing recommendations for diking leases, treater and lineheater stack modification, weed control and soil reconditioning programs.
15. The stack upgrade proposed by Western Research is underway. In the interim, the lineheater burner operating at reduced output using Co-op fuel. Emissions will be monitored and any necessary changes will be implemented.
16. The environmental audit conducted in 1991 will be updated annually during a period of activity. Included in this audit will be participation by both the ERCB and the landowner. This will ensure that the procedures established are maintained.
17. Create a site specific vegetation management plan for both the Dina and the Sparky operation including a monitoring checklist.
18. Provide a small oil spill response trailer and site specific oil and salt-water spill control and cleanup plans.

19. Provide a site specific emergency response policy and procedure including a one complete emergency response exercise per year.
20. Development of a detailed drilling fluid control and disposal program.
21. Development of a detailed construction and drilling schedule integrated into a landowner communication and liaison program.
22. Development of access and service control/monitoring programs including contractors service specifications and training.
23. Both the landowner and the ERCB will be kept abreast of the progress of the development.
24. Amax is receptive to all reasonable suggestions regarding the development and continued operation.

APPENDIX C
AMAX OPERATIONS AT THE 10-16 BATTERY

After being processed at the battery, clean oil is directed to the oil storage tanks, produced water to the water disposal well, and produced gas is used either for fuel purposes at the battery or is directed to the flare stack. All instrument gas used at the battery is sweet gas purchased from a gas co-op. It stated that the treater burners are fuelled by produced gas and in the event of a low pressure condition from produced gas, the burners are automatically converted to sweet co-op gas. Any gas not used for fuel is burned through the flare stack.

All main process vessels are equipped with high liquid level shut-down controls and the treater and free-water knockout vessels are equipped with high pressure shut-down controls. Amax stated this leaves the pressure relief valves on the vessels as a back-up and significantly reduces the chances of fluids being diverted to the flare knockout drum in the event of a high pressure condition. Further, the fire tubes in the treater are equipped with flame failure shut-down controls and all buildings, with the exception of the motor control building, are equipped with fire and H_2S detectors. All instruments, controls and detectors are connected to the programmable logic controller (PLC) which is located in the motor control building.

The PLC is an electronic unit that monitors all vessels, fire tubes, H_2S and fire detectors, pressure and level sensors throughout the battery and initiates the shut-down of portions or all of the battery in the event of an upset. The PLC also sends a telephone alert call to the battery operator. The PLC has a battery power back-up in the event of a power outage. In the event of an emergency shut-down at the battery, the PLC causes the inlet valves to the battery to close, thus preventing further production from entering the battery. With the valves closed, the resulting higher build-up in the flow lines will activate the high pressure shut-down controls at the satellites and wells.

The water disposal system consists of two storage tanks and three positive displacement pumps. The pumps are controlled by high and low level switches located on the tanks and the water is pumped down a disposal well located at Lsd 14-16-41-1 W4M. The pumps are housed in a separate building that is equipped with H_2S and fire detectors and the tanks are tied into the VRU.

There are six product storage tanks at the battery, five of which are used for oil storage and one for condensate storage. The oil tanks are piped to a main oil pipeline. All tanks are equipped with a thief hatch to prevent over pressuring. The tanks are interconnected with over-flow lines and all are tied into the VRU. It stated there are no high and low level shut-down controls on the tanks although during normal operations only one tank is used for oil storage and shipping. The four additional tanks provide for the storage of approximately one week of production to the battery in the event of the inability to ship the oil through the pipeline.

A VRU system at the battery gathers all gas that breaks out of the water and oil within the storage tanks and directs the gas to the flare. The VRU consists of two rotary compressors that are driven by electric motors. The compressors operate singly on alternate weeks and in the event of a failure of the operating compressor the second will automatically start. If both units fail the PLC will initiate a battery shut-down. The compressors are also equipped with high temperature and high pressure shut-down controls, however, the automatic bypass eliminates the need for a low pressure shut-down control.

The battery utilizes a continuous pilot flare stack to combust all gathered vapours and unused produced gas. The continuous pilot is supplied by sweet co-op gas and is equipped with an automatic igniter to ensure that the flame is re-lit if it is extinguished. A flame arrester is located one metre below the top of the stack and a liquid catcher and drain are located at the bottom of the stack.

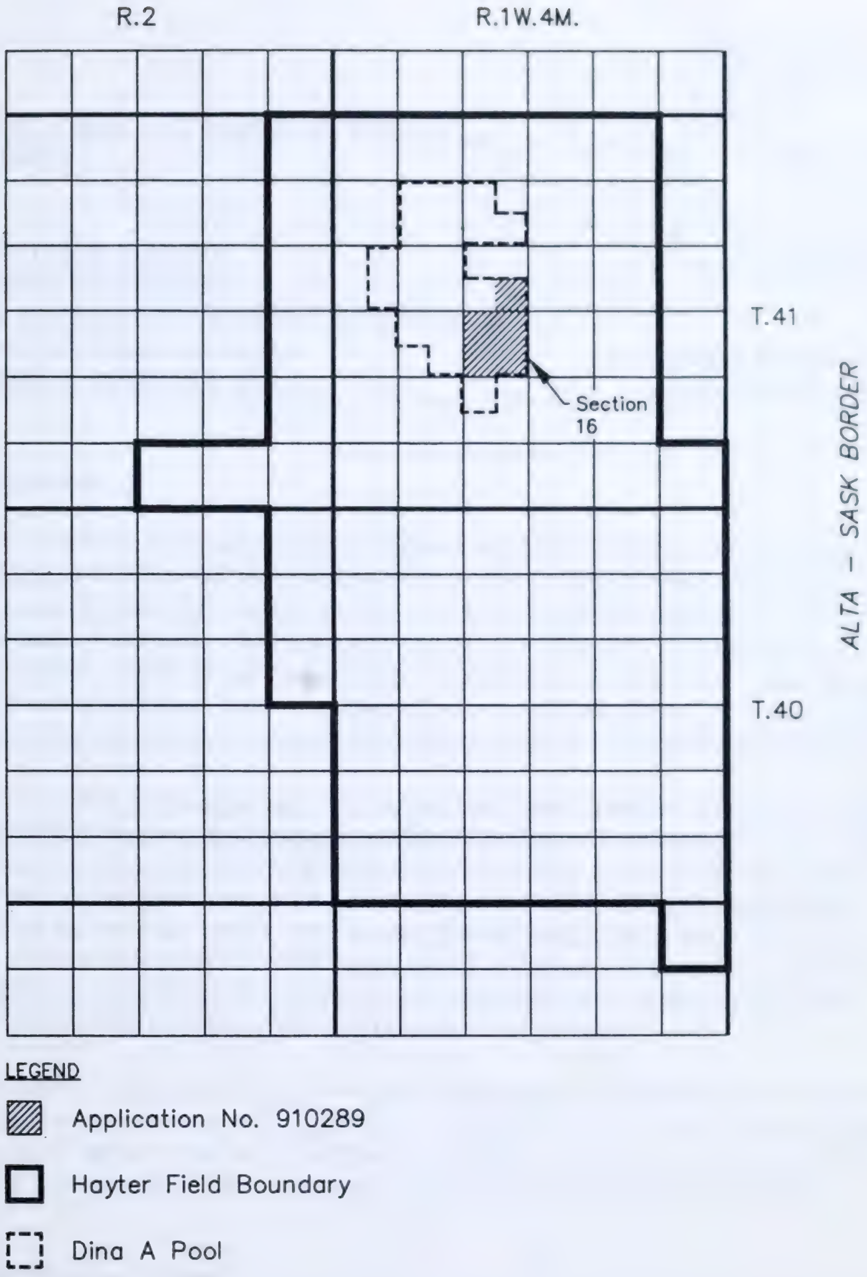


FIGURE 1
HAYTER FIELD AND AREA OF APPLICATION

RECEIVED
FEB 2 [illegible] 1997
WEIR MEMORIAL LAW LIBRARY
[illegible]

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ANDERSON OIL & GAS INC.
APPLICATION TO SUSPEND
CLAUSE 5, SUBCLAUSE (B) OF DECISION D 93-3
SIMON AND MICHAEL SKINNER
HAYTER FIELD, PROVOST AREA

Addendum to Decision D 93-3
Application No. 1003897

1.1 Background

Decision D 93-3 resulted from an application by Simon and Michael Skinner (the Skinners) pursuant to Section 42 of the Oil and Gas Conservation Act to review certain licences and approvals granted to Amax Petroleum of Canada Inc. In 1993 Amax was the lessee and operator of the Hayter field oil production facilities located on the Skinner's dairy farm in Section 16, Township 41, Range 1, West of the 4th Meridian. Concurrently, Amax applied to the Energy Resources Conservation Board, (now the Alberta Energy and Utilities Board) for approval to drill additional wells and construct associated production facilities on the Skinner's dairy farm.

The Skinners requested a review because they believed the Amax operation created undue risk to the livelihood of their families, their personal health and the health of their dairy livestock. The concentration and proximity of oil field development to their dairy operation created impacts greater than that normally associated with similar oil field operations. They maintained that experiences with battery fires, odours, crop damage from oil sprays, salt water spills, and the ever present risk that their domestic water supply would be contaminated created a high level of stress in the families and threaten the viability of the family dairy farm. Approval of Amax's applications to expand its facilities would only exacerbate the problem.

Following a lengthy hearing, the Energy Resources Conservation Board issued D 93-3 which contained a number of directions including clause 5, subclause (b). This clause required the nine wells located in the Skinners pasture to be abandoned and site reclamation started by 2 March 1997. Refer to Decision D 93-3 for a complete discussion of the issues and views of the participants.

1.2 Application No. 1003897

Anderson, the current licensee of record for these facilities, submitted that it has reduced the impact of its operations on the Skinners and their dairy farm by improving its communication with them and using good oilfield practices. In the two and a half years it has operated the facilities, Anderson has worked diligently with the Skinners to build a relationship of mutual trust which would allow the oil field operation and the Skinner's dairy farm to coexist. As a result of Anderson's improved relationship with the Skinners and its commitment to maintain the quality of its operation, the Skinners have agreed to defer the abandonment of the nine wells located in the pasture.

1.3 Decision

The Board acknowledges the improvement Anderson has accomplished in its operations and communication with the Skinner family. It also notes the Skinners support of Anderson's application. Having considered the evidence, the Board has decided to waive the requirements of clause 5, subclause (b) of Decision D 93-3. The Board notes that either Anderson or the Skinners may apply to have the clause reinstated subject to the mutually agreed upon terms in Application No. 1003897.

DATED at Calgary, Alberta, on 13 January 1997.

ALBERTA ENERGY AND UTILITIES BOARD

F. Mink
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

PROCEEDING RESULTING FROM A REQUEST BY NORTHWESTERN UTILITIES LIMITED FOR THE BOARD TO REVIEW DECISION D 91-6 PURSUANT TO SECTION 42 OF THE ENERGY RESOURCES CONSERVATION ACT

Decision D 93-4
Proceeding No. 921563

1 INTRODUCTION

1.1 Background

The Energy Resources Conservation Board issued Decision D 91-6 which approved Applications No. 910114, 910116, and 910505 made by The Imperial Pipeline Company, Limited (Imperial) and Application No. 910115 made by Esso Resources (1989) Limited to convert a portion of the Edmonton to Sundre Expansion Pipeline (ESEP) from blended crude bitumen to natural gas service. Subsequent to Decision D 91-6, Imperial applied to reconfigure its pipeline systems in the area of the ESEP conversion and to construct new facilities to move blended crude bitumen to Montana, and light oil from Southern Alberta to Edmonton.

1.2 Proceeding

The proceeding resulted from a request made by Northwestern Utilities Limited (NUL) pursuant to Section 42 of the Energy Resources Conservation Act for a review and variance of Decision D 91-6 and the related permits and licences issued pursuant to the Pipeline Act.

1.3 Hearing

The application was considered at a Board hearing in Calgary, Alberta on 10 and 11 February 1993, with F. J. Mink, P.Eng. (Chairman), and Acting Board Members, K. G. Sharp, P.Eng. and J. R. Nichol, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

2 ISSUES

In considering the request for a review by NUL and after reviewing the submissions, the Board identified two issues:

- whether the additional facilities proposed to reconfigure the Imperial pipeline system are related to the ESEP conversion, and whether these additional facilities sufficiently undermine the cost effectiveness of crude movements to Montana, and
- the merits of alternate service offered by NUL to the extent to which that service is varied from the original offer by NUL.

3 CRUDE MOVEMENTS TO MONTANA

Imperial explained that its system reconfiguration is dictated by additional requirements for crude oil transportation which are independent of the status of ESEP. NUL presented an analysis showing that if Imperial cancelled the ESEP conversion and utilized some of NUL's facilities, Imperial could realize significant capital cost savings and still meet the expected requirements for oil transportation. Imperial acknowledged NUL's contention that the total project costs would be higher under its proposal to maintain liquid hydrocarbons shipments in both a north and south direction, however, it did not agree with NUL's estimate of the magnitude of the cost differences. Imperial confirmed that, despite the fact there would be increases in the capital costs of maintaining oil shipments in both directions, there would be no increase in tariffs for non-Imperial oil shippers. That is, the tariffs would be equivalent to or lower than those possible if ESEP is not converted to gas service. Differences in costs would be absorbed by Imperial as part of its operating cost of moving proprietary gas on the ESEP conversion. In view of Imperial's commitment, the Board is satisfied that the additional costs would not be rolled into pipeline tariffs for third party oil producers, and that such costs would be a business risk assumed by Imperial alone.

The Board believes that if ESEP is not converted to gas service, it could be made available for other service, and perhaps result in fewer facilities being required for the overall Imperial system reconfiguration. However, having regard for the commitments made by Imperial, the Board is satisfied that the additional facilities now proposed are mainly related to changes in the light crude oil delivery requirements and, as such, would not undermine the cost effectiveness of crude movements to Montana.

4 ALTERNATE NUL SERVICE

NUL submitted that it could provide the same or better service to Imperial than the ESEP conversion. NUL emphasized its willingness to provide competitive service and listed the ways in which it could address Imperial's concerns. However, Imperial was not satisfied that NUL could provide the long-term operating flexibility required and stated that further negotiations would likely not be productive. The Board acknowledges that Imperial's reluctance to specify its long-term strategic business interests for converting ESEP frustrated NUL's efforts to satisfy Imperial's needs for flexible service. Based on the evidence at the hearing, the Board believes a suitable alternative to the conversion of ESEP is not likely to be negotiated.

In the Board's view NUL's desire to use its facilities at a higher capacity for the benefit of its customers and Imperial's desire to use its own facilities in a manner consistent with its corporate plans, represent the major public interest issues. The Board believes that its responsibilities justify overruling corporate preferences where there is a clear public interest reason to do so. However, in the absence of significant public interest aspects, such as environmental impacts or unnecessary public expenditures, suitable alternative service should be a matter between the parties involved. In this case there are no apparent environmental impacts, public expenditures, or other such issues. Further, the additional project costs, over and above those possible if ESEP is not converted to gas service, would be borne solely by Imperial; these costs would not be passed on to other oil shippers. Finally, the Board accepts Imperial's statement that its long-term interests for converting ESEP to gas service do not involve the transportation of third party gas, which was raised as a concern by NUL.

The Board notes Imperial's contention that the higher costs of the Imperial proposal are justified by the operating flexibility it affords. While the NUL proposal appears to be less costly, its offer does not appear to provide the same level of service as Imperial can provide itself. Imperial also argued that the nature of NUL's rate making/design represented a commercial risk that made its offer less attractive.

After deliberating on the evidence and arguments submitted at the hearing, the Board continues to be of the view that the ESEP conversion meets the broad public interest of Alberta. It is the Board's view that Decision D 91-6 continues to be a satisfactory recognition of the competing interests and the Board does not see sufficient reason or changed circumstances to overrule Imperial's preference to convert ESEP to gas service.

The Board indicated in its Notice of Hearing that it would not deal with the generic issue of bypass in the province. Should the generic issue of bypass merit a public review the Board expects that such a review would be based on broad industry input or result from a government policy directive.

5 CONCLUSION

The Board is satisfied that circumstances have not changed sufficiently to warrant a variance of Decision D 91-6.

6 DECISION

The Board confirms its approval of Applications No. 910114, 910116, and 910505 by the Imperial and Application No. 910115 by Esso Resources (1989) Limited.

Dated at Calgary, Alberta, on 29 March 1993.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.*
Vice Chairman

K. G. Sharp, P.Eng.
Acting Board Member

JR Nichol
J. R. Nichol, P.Eng.
Acting Board Member

---

* Mr. Mink was unavailable for signature but concurs with the contents and with the issuing of this report.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The Imperial Pipe Line Company Limited Imperial Oil Resources Limited (Imperial) D. G. Davis	C. D. Bird, P.Eng. W. Feil, P.Eng. R.H.G. Millar, P.Eng.
Northwestern Utilities Limited (NUL) B.K. O'Ferrall	R. Armstrong, P.Eng. G. M. Engbloom, P.Eng. J. F. Engler W. L. Graburn, P.Eng.
	N. Lenstra, P.Eng. G. Walker, P.Eng. both of Proactive Technologies International, Inc.
City of Edmonton L. M. Sherwood	
Koch Pipelines Ltd. K. F. Miller	
Energy Resources Conservation Board R. D. Heggie P. K. Ferensowicz K. M. Johnston P. Kahler S. C. Lee, P.Eng. T. J. Pesta, P.Eng.	

The Alberta Petroleum Marketing Commission, Amoco Canada Petroleum Company Limited, Conoco Inc., and Gulf Canada Resources registered as interested parties.

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATIONS BY AMOCO CANADA PETROLEUM COMPANY LTD.,
THE IMPERIAL PIPE LINE COMPANY, LIMITED AND KOCH PIPELINES LTD.
FOR PERMITS TO CONSTRUCT CRUDE OIL/CONDENSATE/BLENDED BITUMEN
PIPELINES AND RELATED FACILITIES IN SUNDRE/EDMONTON AREAS

APPLICATION BY NORTHWESTERN UTILITIES LIMITED
FOR A REVIEW AND VARIANCE OF DECISION D 91-6

Decision D 93-5
Applications No. 921014 to 921026

1 INTRODUCTION

1.1 Applications

Pursuant to Part 4 of the Pipeline Act, Amoco Canada Petroleum Company Ltd. (Amoco), the Imperial Pipe Line Company, Limited (Imperial), and Koch Pipelines Ltd. (Koch) submitted the following applications for approval to construct pipelines and related facilities for the transportation of crude oils, condensate, and blended bitumen between the Sundre area and the Edmonton area. The locations of the proposed facilities are shown on the attached figure.

Applications No. 921014 and 921015

Amoco applied for permits to construct approximately 60.7 kilometres (km) of 219.1 millimetre (mm) outside diameter (O.D.) pipeline to transport sour crude oil (sulphur content ≥ 0.5 per cent by weight) from a pipeline tie-in point in Legal Subdivision (Lsd) 10 of Section 19, Township 37, Range 3, West of the 5th Meridian near Sylvan Lake to a proposed tank farm in Lsd 12-23-42-2 W5M near Rimbey.

Applications No. 921016 to 921020

Amoco applied for permits to construct approximately 12.7 km of associated laterals in the Sylvan Lake area, and tankage facilities in Lsd 12-23-42-2 W5M, near Rimbey, as part of the sour crude oil segregation project.

Application No. 921021

Imperial applied for a permit to construct an 895 kilowatt (kW) pump station in Lsd 13-19-40-2 W5M near Bentley, and approximately 42.5 km of 323.9 mm O.D. pipeline to transport blended bitumen from the Bonnie Glen junction in Lsd 9-14-47-27 W4M to a pipeline tie-in point in Lsd 13-33-43-1 W5M near Springdale.

Application No. 921022

Imperial applied for a permit to construct two 2984 kW pump stations, one in Lsd 6-3-46-28 W4M near Ma-Me-O Beach, and one in Lsd 16-34-47-26 W4M near Pipestone, and approximately 56.8 km of 323.9 mm O.D. pipeline to transport crude oil from the Bonnie Glen junction to a pipeline tie-in point in Lsd 4-28-51-24 W4M near Ellerslie.

Applications No. 921023 and 921024

Imperial applied to increase the maximum operating pressure of the existing Bonnie Glen pipeline between Rimbey and Edmonton, and to reverse the direction of flow and change substance (from light crude oil to blended bitumen) of a portion of the 406.4 mm O.D. segment of the Bonnie Glen pipeline from Lsd 4-28-51-24 W4M near Ellerslie to the Bonnie Glen junction.

Application No. 921025

Koch applied for a permit to construct a 2600 kW pump station and a tank farm in Lsd 12-23-42-2 W5M near Rimbey, and approximately 130 km of 406.4 mm O.D. pipeline to transport crude oils and condensate from the proposed pump station at Rimbey to a pipeline tie-in point in Lsd 3-5-53-23 W4M near Edmonton.

Application No. 921026

Pursuant to Section 42 of the Energy Resources Conservation Act, Northwestern Utilities Limited (NUL) applied for a review and variance of Decision D 91-6 respecting the Edmonton to Sundre Expansion Pipeline (ESEP) conversion.

1.2 Background Information

Amoco currently operates the Rangeland pipeline for the transportation of sweet crude oil (sulphur content < 0.5 per cent by weight) from the Sundre area to the Imperial Bonnie Glen system at Rimbey. As a result of Conoco Inc.'s (Conoco's) change of refinery feedstock requirements, the shutdown of the Canadian Turbo Inc. (Turbo) refinery in Calgary and the continued production of sour crude oil in the Sylvan Lake/Sundre areas, Amoco submitted applications to install sour crude oil segregation facilities in the Sylvan Lake area, a tank farm near Rimbey, and a pipeline from the Sylvan Lake area to Rimbey for the transportation of sour crude oil.

Concurrent to the Amoco applications, Koch proposed to install batching facilities at Rimbey and a pipeline from Rimbey to the Edmonton area to accommodate Amoco's segregated crude oils as well as condensate from Shell Canada Limited's (Shell's) Caroline gas plant.

Imperial currently transports Cold Lake bitumen blend from Edmonton to Sundre via the ESEP. It also transports sweet crude oil from Rimbey to the Edmonton area through the existing Bonnie Glen pipeline. Following a hearing held in Edmonton on 30 April and 1 and 2 May 1991, a portion of the ESEP between Ellerslie and Homeglen was approved for conversion from blended bitumen to natural gas service. Detailed discussions are included in Decision D 91-6. Recently, in order to provide the batching service similar to that proposed by Koch as well as to continue to ship blended bitumen to the Sundre area, Imperial submitted applications to install additional pump stations near Bentley and Ma-Me-O Beach and additional pipelines between Springdale and Ellerslie. The new pipelines would be constructed in a location relatively close to the ESEP.

NUL, which currently operates some gas pipelines in the Leduc area and which intervened at the April/May 1991 ESEP conversion hearing, was of the view that neither of the proposed Imperial pipelines is required if ESEP was to remain in oil service. It therefore applied under section 42 of the

Energy Resources Conservation Act for a review and variance of Decision D 91-6, stating that circumstances upon which Decision D 91-6 was based have either changed or did not materialize as predicted.

A pre-hearing meeting was held in Calgary on 26 August 1992 to consider procedural and timing matters respecting the above applications. Following the pre-hearing meeting the Board agreed that the Amoco, Koch, and Imperial applications would be jointly considered at a public hearing. The Board denied the NUL application on the basis that the current circumstances would not materially affect Decision D 91-6.

2 HEARING

The applications were considered at a public hearing in Calgary, Alberta on 14 and 15 October 1992, with Board Members F. J. Mink, P.Eng., R. G. Evans, P.Eng., and N. G. Berndtsson, P.Eng. sitting. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principles and Representatives (Abbreviations Used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) D. A. Holgate	D.G. Moe, P.Eng. A.B. Charlesworth G.K. Luft K.W. Williams, P.Eng.
The Imperial Pipe Line Company, Limited (Imperial) D.G. Davies	R.A. Hill, P.Eng. R.D. Shiells, P.Eng. C.D. Bird, P.Eng. R.P. Delaney, P.Eng. W.H. Feil, P.Eng. G.W. Kalyniuk, P.Eng.
Koch Pipelines Ltd. (Koch) K.F. Miller	R.C. Aldridge F. Janzen, P.Eng.
Northwestern Utilities Limited (NUL) B.K. O'Ferrall	
Alberta Natural Gas Company Ltd. (ANG) A. Menzies	
Alberta Petroleum Marketing Commission (APMC) P.A. McCunn-Miller	
Conoco Canada Limited (Conoco) A.R. Ferguson	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principles and Representatives (Abbreviations Used in Report)	Witnesses
Crestar Energy Inc. (Crestar) T.A. Pocza	
Federated Pipe Lines Ltd. (Federated) C.I. MacLean	
Gulf Canada Resources Limited (Gulf) K. Smee	
Home Oil Company Limited (Home) C.I. MacLean	
Northridge Petroleum Marketing Inc. (Northridge) C.M. Olson	
PanCanadian Petroleum Limited (Pan Canadian) K.J. Hadley	
Rimbey Pipeline Co. Ltd. (Rimbey) H.B. Ward	
Shell Canada Limited (Shell) E.S. Decter	B. Mitchell R. Gall
Energy Resources Conservation Board Staff M. Bruni S. Lee, P.Eng. P. Ferensowicz K. Johnston P. Kahler	

At the outset of the hearing, Koch proposed to amend its application to conform to the Imperial applications. Koch stated that it would not seek approval to construct any of the proposed facilities outlined in the original Koch application, but that it would like to put all of its filings on record for the purpose of the hearing. Imperial supported Koch's proposed amendment, commenting that Koch had already agreed to purchase 50 per cent of the existing Bonnie Glen pipeline and to participate with Imperial on a 50 per cent basis in the construction of the Bonnie Glen expansion facilities. Both Imperial and Koch requested that approval be granted for the new construction and that the permit be issued to Imperial on behalf of Imperial and Koch.

At the outset of the hearing, NUL asked for permission to adduce evidence relating to ESEP conversion. After considering the arguments by all parties, the Board ruled it was not prepared to consider issues involving the transportation of natural gas at this hearing. NUL chose not to participate further and withdrew from the hearing. Following the hearing, NUL applied again for a review and variance of Decision D 91-6 (Proceeding No. 921563), stating that there had been a substantial and material change in circumstances and in facts since the issuance of Decision D 91-6. The Board granted NUL's request and held a public hearing in Calgary, Alberta on 10 and 11 February 1993 to hear evidence on the merits of the arguments. The Board concluded that circumstances had not changed sufficiently to warrant a variance of Decision D 91-6. Detailed discussions are included in Decision D 93-4.

After the hearing in October 1992, the Board issued a memorandum of decision granting approval to the Amoco applications with reasons to follow. The approval was granted on the basis that there is a need for Amoco's proposed facilities and that no objections were raised by interested parties.

The Board recognizes that Koch supports the Imperial applications and, subject to its participation in the Imperial proposal, it would not seek approval to construct any of its own proposed facilities. The Board does not see any need to deliberate further on the Koch application. Should the Board find the Imperial applications to be satisfactory it would issue the permit in the name of Imperial and leave the participation by Koch to commercial arrangements between the parties.

3 TECHNICAL/ENVIRONMENTAL MATTERS

The Board notes that no interveners questioned the technical or environmental matters relating to these applications. The Board has reviewed the applications for the proposed pipelines and has found them technically and environmentally satisfactory. The Board notes that the Imperial's Development and Reclamation Reports are currently being reviewed by the Minister of Environmental Protection. If the Imperial applications are approved, the Board will require that any outstanding environmental concerns be addressed.

The Imperial proposal requires the requalification of the existing 406.4 mm O.D. pipeline for an increase in the maximum operating pressure and a change of substance. The Board will require that the existing pipeline be successfully tested to meet the new operating requirements.

4 LANDOWNER CONCERNS

4.1 Amoco Applications (No. 921014 to 921020)

The Board notes that all landowners along the proposed Amoco pipeline were satisfied with the routing.

4.2 Imperial Applications (No. 921021 to 921024)

Imperial stated that there are two landowners along its light crude oil pipeline route from whom consents for routing have not been obtained. Mr. John Novak (owner of north-west quarter 9-51-24 W4M) was concerned about the routing across his property and Mr. Cornelius Van Someren (resident of south-east quarter 3-48-26 W4M) about noise from the Pipestone pump station. Imperial indicated to the Board that it intends to install the pipeline in the same right-of-way as the existing ESEP across Mr. Novak's property. It also indicated that it had agreed with Mr. Van Someren to conduct sound level studies before and after the installation of the proposed facilities to ensure that the requirements of the noise directive ID 92-2 are met. In both cases, Imperial had advised the landowners of the hearing and had encouraged them to attend and express their concerns. Both of the landowners were notified of the hearing, but neither attended.

With respect to the blended bitumen pipeline alignment Imperial stated that, although it had not personally contacted the landowners, it did not anticipate any objections. It stated that Federated, while acting as its agent, had previously contacted these landowners regarding the dual line construction and that there were no objections at that time.

The Board is satisfied that Imperial would continue to follow-up with landowner contacts and negotiations and, if there is any objection, expects Imperial not to proceed with construction until the matter is resolved. The Board therefore does not consider landowner concerns to be an issue.

5 ISSUE

The Board believes that the only remaining issue relevant to the applications is the need for the pipelines.

6 NEED FOR THE PIPELINES

6.1 Views of the Applicants

The need for significant changes to Alberta's Rangeland and Bonnie Glen pipeline systems, as stated by both the applicants, results from a number of market factors. The conversion of Conoco's Billings, Montana refinery from light Canadian crude to heavy Canadian crude, the shut down of the Turbo refinery at Balzac and the start-up of Shell's Caroline gas plant have prompted significant alteration to the north- and southbound crude movements from southern Alberta.

6.1.1 Views of Amoco

Amoco indicated that its Rangeland pipeline system is operating at close to its capacity in northbound crude deliveries between Sundre and Rimbey. Deliveries to Rimbey have increased as a result of the changes to Conoco's refinery and closure of Turbo's refinery. Deliveries of light sweet crude averaged approximately 3500 m^3/d in 1991 and reached an average of 9130 m^3/d in June 1992.

The higher sulphur content of these deliveries has forced Rangeland to refuse commingling of some sour crude into the common stream to maintain the 0.5 per cent sulphur limit. This in turn has forced sour crude in the area to be shut in, or trucked at a higher cost to producers.

Rangeland has a capacity on the common stream of 11 000 m^3/d and is forecasting sweet crude deliveries to reach 10 070 m^3/d for 1993. In addition, deliveries of 2000 m^3/d of sour crude were forecast for 1993. In order to deliver the expected volumes of sour crude oil and maintain the sulphur limits of the common stream, changes to the Rangeland system would be required. The applied-for Rangeland facilities were designed to segregate the common and sour stream volumes. These facilities are expected to alleviate the problem of shut-in sour crude, displace trucked sour crude oil from the area, and provide a net benefit to producers and the province.

6.1.2 Views of Imperial

Located downstream of the Rangeland system, Imperial's Bonnie Glen system is also affected by the developments at Conoco and at Turbo. Currently, the operating capacity of the Bonnie Glen system at Rimbey is 11 000 m^3/d and at Edmonton is 15 500 m^3/d. Imperial reported that the Bonnie Glen system has received up to 10 800 m^3/d of Rangeland common stream deliveries at Rimbey and based on forecast deliveries to Rimbey, the Bonnie Glen system would need to be expanded to handle the higher volumes.

Imperial submitted that in addition to the estimated 12 070 m^3/d of sweet and sour crude oil expected to be delivered at Rimbey by Rangeland, 2820 m^3/d of Caroline condensate will require transportation to Edmonton on the Bonnie Glen system. Therefore, the existing Bonnie Glen pipeline system must be expanded by adding tankage and pumping capacity. The proposed system will be operated in a batching mode to accommodate the segregated crude oils from Rangeland and the Caroline condensate.

Imperial also indicated that it has received a request to provide transportation for 4000 m^3/d of Cold Lake blend from Edmonton to Rimbey. The modifications to Conoco's refinery are expected to result in some demand for Cold Lake blend. Imperial stated that it has agreed with Conoco on the general terms and conditions for the supply of 2400 m^3/d of Cold Lake blend. Imperial also stated that it has an agreement to supply 1600 m^3/d of Cold Lake blend to Exxon in Montana. Therefore, as indicated by Imperial, the market conditions justify the need to ship increased volumes of Cold Lake blend south to Montana.

6.2 Views of the Interveners

There were no interveners questioning the need for the pipelines proposed by Amoco and Imperial. Imperial withdrew its earlier intervention to the Amoco application, leaving Amoco with the only proposal to provide sour segregation service. Amoco and Imperial expressed support for each other's proposed pipelines. Support for these facilities was also expressed by Koch, Federated, Shell, and the APMC. Koch also supported Imperial's applied-for Cold Lake blend facilities.

6.3 Views of the Board

The Board is satisfied that markets support a need to ship increased volumes of light crude oil and condensate north to Edmonton and that segregation of sweet and sour crude oil, as proposed by Amoco, would be beneficial to producers.

The Board acknowledges that the agreements with refiners in Montana to take Cold Lake blend necessitate the proposed changes to Imperial's Cold Lake blend system.

7 DECISION

By its memorandum of decision dated 16 October 1992, the Board granted Applications No. 921014 to 921020 by Amoco Canada Petroleum Company Ltd. and this report provides the reasons for that decision. The Minister of Environmental Protection approved these applications on 21 October 1992.

The Board is prepared to grant Applications No. 921021 to 921024 by Imperial Pipe Line Company Limited, for the reasons discussed in this report, subject to the receipt of the approval of the Minister of Environmental Protection respecting environmental matters, and subject to the following:

- the existing 406.4 mm O.D. pipeline be successfully tested to meet the new operating requirements, and
- Imperial not to proceed with construction until any landowner objections are resolved.

DATED at Calgary, Alberta, on 3 May 1993.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

R G Evans

R. G. Evans, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION TO AMEND APPROVAL NO. 5641
MILDRED LAKE OIL SANDS OPERATION
SYNCRUDE CANADA LTD.

Memorandum of Decision
Pre-Hearing Meeting
Application No. 921321

1 INTRODUCTION

On 22 April 1993, the Energy Resources Conservation Board convened a meeting in Fort McMurray to consider procedural matters related to the anticipated hearing of Application No. 921321 submitted by Syncrude Canada Ltd.

The presiding panel included F. J. Mink, Chairman, B. F. Bietz, and R. G. Evans. The names of participants who appeared at the meeting are listed below:

PARTICIPANTS AT THE MEETING

Participants (Abbreviations Used in Report)	**Representatives**
Syncrude Canada Ltd. (Syncrude)	F. M. Saville, Q.C. A. W. Hyndman B. Friesen
Fort McKay First Nation/ Fort McKay Metis Local 122 (Fort McKay)	J. N. Slavik Chief J. Boucher R. Faichney
Syncrude Environmental Assessment Coalition (SEAC)	B. K. O'Ferrall P. McInnes
Edmonton Friends of the North Environmental Society/Fort McMurray Local of the Alberta Trappers Association	M. Bronaugh J. Rogers
Athabasca Tribal Corporation (ATC)	Chief B. Cree
Athabasca Chipewyan Band of Fort Chipewyan (Chipewyan Band)	J. N. Slavik
Energy Resources Conservation Board (Board)	R. D. Heggie T. G. Abel J. J. Sutherland

Issues raised at the meeting generally fall into three categories:

- Hearing Details;
- Intervener Status and Funding; and
- Environmental Protection and Enhancement Act.

2 HEARING DETAILS

Syncrude favoured that the hearing be held in June 1993 and although the majority of the other participants believed this could be accommodated, all preferred a September 1993 date to allow adequate preparation time and to avoid some significant timing conflicts that could prevent the full involvement of all the participants. Of further concern was the timing for the completion of a report on the subject of fine tailings management and reclamation, being prepared by the Alberta Research Council (ARC) for Fort McKay, which would not be completed until 21 May 1993.

The Board believes that in order to allow sufficient time for all the basic information to be received and for interventions to be prepared, submitted, and reviewed by all parties, the hearing could not realistically begin until the latter part of June. Having regard for the possible duration of the hearing and the July scheduling conflicts of some participants, the Board has decided to schedule the hearing to commence on Wednesday, 8 September 1993. The Board has also decided that the deadline for the filing of interventions will be set at 28 June 1993, which will allow ample time for all participants to review submissions and prepare for the hearing.

The Board has also considered possible venues for the hearing and has decided it will be held in Fort McMurray. However, in response to the request of Fort McKay, the Board is prepared to give consideration to holding a limited portion of the hearing in the Fort McKay community, the details of which would be worked out by the Board in consultation with Fort McKay and Syncrude.

Counsel for Fort McKay requested some direction on how the Board would deal with final argument. In this case, the Board would expect to follow its normal practice of proceeding to final argument immediately following the evidentiary portion of the hearing. Further, in the interest of ensuring an effective hearing, the Board will issue procedural guidelines to address additional concerns related to the efficient presentation of evidence and other procedural matters. These procedural guidelines will be issued by the Board shortly.

Both Fort McKay and the SEAC raised concerns regarding whether a Board panel would be able to adequately address all technical issues. The Board notes that it has not yet received the interventions but can assure participants that all issues will be carefully examined and the Board will take whatever steps are necessary to ensure the issues are fairly and effectively considered.

3 INTERVENER STATUS AND FUNDING

Participants, and in particular Fort McKay and SEAC, requested that the Board provide further detail and clarification regarding intervener expenses that would be eligible under the Local Interveners' Costs Regulation. The Board does not believe that further clarification of, or advance rulings on, eligible expenses is necessary or warranted as sufficient direction and guidance is provided to local interveners in ERCB Guide G-31, Guidelines Respecting Applications for Local Interveners' Costs Awards. The Board continues to believe that expenditures associated with interventions should be prudent and the Board is not in a position, in advance of a hearing, to pass judgement on the scope of such interventions. It is incumbent on those preparing interventions to recognize the risk that costs will not be reimbursed if they are unreasonable. The Board believes counsel involved in this hearing are sufficiently experienced to guide interveners in exercising proper judgement, in accordance with Guide G-31, when making decisions regarding expenditures related to the preparation of an intervention or participating at a hearing. In broad terms, the Board believes the $125 000 already provided to Fort McKay by Syncrude would be considered adequate, in most instances, to allow an intervener to prepare for and participate in a hearing. With respect to the involvement of ARC staff in the hearing, the Board notes that proper representation of the ARC report should be eligible for cost recovery. The Board would expect counsel to assess the degree to which individuals involved in preparing the report are necessary to prepare for or participate in the hearing. The Board also notes that at least two items (Nos. 4 and 6) in Schedule 'A', paragraph A to the contract between Fort McKay and ARC dated 11 March 1993, appear to make specific reference to preparation for a hearing.

Submissions by two participants, ATC and the Chipewyan Band requested rulings on their status as local interveners. For a party to qualify as a local intervener, it is necessary to demonstrate an interest in land which may be affected. The Board is of the view that the onus rests upon the party applying for local intervenor status to show that the land is directly and adversely affected. Some factors the Board has taken into account in past decisions include proximity of the land to the proposed facility as well as emissions. These factors are merely noted for illustrative purposes and are not intended as an exhaustive list.

In this case the Board is not in a position to qualify the ATC and the Chipewyan Band as local interveners in advance of the hearing as the Board finds that neither party has satisfied the test set out above. In the case of ATC, the Board does accept that the issue of socio-economic impacts is a matter of interest and would not object if the study, as proposed by ATC, were produced under the direction of Fort McKay. In the case of the Chipewyan Band, the Board expects that many, if not all of the concerns raised by the Chipewyan Band can and will be addressed in the Fort McKay intervention.

4 ENVIRONMENTAL PROTECTION AND ENHANCEMENT ACT (EPEA)

Fort McKay and SEAC raised the issue of the EPEA and whether the Board might consider Syncrude's application and any associated decisions as if the EPEA had been proclaimed. The Board would simply note that on 21 April 1993; the EPEA was proclaimed in force on 1 September 1993.

DATED at Calgary, Alberta on 6 May 1993.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

R. G. Evans
R. G. Evans, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

CHANCELLOR ENERGY RESOURCES INC.
APPLICATION TO CONSTRUCT AND OPERATE A SWEET GAS PROCESSING PLANT IN THE STEWART FIELD

Decision D 93-6
Application No. 921683

1 INTRODUCTION

1.1 Application, Interventions, and Hearing

Chancellor Energy Resources Inc. (Chancellor) received Board Approval No. 7112 on 10 February 1993 for approval to construct and operate a sweet gas processing plant to be located in Legal Subdivision 1 of Section 23, Township 32, Range 28, West of the 4th Meridian (Lsd 1-23-32-28 W4M) (the 1-23 plant). The plant would be designed to process a maximum of 285 x 10^3 m^3/d of raw sweet gas, from which 281 x 10^3 m^3/d of sales gas and 5.0 m^3/d of LPG mix would be recovered. No sulphur or sulphur compounds would be emitted to the atmosphere. The processed gas would be pipelined some 19.0 kilometres (km) south to a sales gas pipeline.

Amerada Hess Canada Ltd. (Amerada) submitted an intervention on 11 March 1993 pursuant to section 43 of the Energy Resources Conservation Act requesting that a hearing be held to consider Chancellor's Application No. 921683 and plant Board Approval No. 7112. Amerada which operates a sour gas plant in Lsd 6-18-32-1 W5M (the 6-18 plant) stated that as a gas plant owner in the area, it was an affected party. Amerada identified an alternative proposal, suggesting that the Chancellor raw gas should be transported some 19.0 km west to the Amerada 6-18 plant for processing and delivery to a sales gas pipeline. A map of the area is attached.

The application was considered at a public hearing in Calgary, Alberta on 20 April 1993, by Board Member R. G. Evans, P.Eng. and Acting Board Members R. G. Paterson, P.Eng. and J. R. Nichol, P.Eng. The participants are listed on following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Chancellor Energy Resources Inc. (Chancellor) F. M. Saville, Q.C.	S. Austin, C.A. C. Hanson, P.Eng. H. Spence, R.E.T. K. Farries, P.Eng. of Farries Engineering (1977) Ltd. P. O'Rourke, P.Eng. of O'Rourke Engineering Ltd.
Amerada Hess Canada Ltd. (Amerada) H. Locke	R. McIntosh, P.Geol. D. Nelson, P.Eng. D. Krouse, P.Eng.

THOSE WHO APPEARED AT THE HEARING (Cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Resources Conservation Board Staff R. D. Heggie M. Semchuck, C.E.T. J. A. Wickens, C.E.T.	

2 ISSUES

In assessing this application, the Board believes that the central issue is plant proliferation as it relates to whether the approval of a new plant would be in the public interest. In reaching a decision in this regard the Board believes that availability of surplus processing capacity is not the sole or key basis on which to determine the disposition of the application. The decision must have regard for:

- public concerns about the proposal,
- environmental impacts,
- economics of a new plant compared to using an existing plant, and
- overall public interest.

3 PUBLIC CONCERNS ABOUT THE PROPOSAL

During the hearing both parties agreed that there were no outstanding public concerns as related to area residents and landowners. Chancellor, as part of its application, provided evidence which demonstrated that no members of the public had objected to its proposed gas plant. The Board acknowledges this and does not see public impacts as an issue in this case.

4 ENVIRONMENTAL IMPACTS

In assessing the environmental impacts of the opposing proposals, the Board must have regard for the site specific impacts associated with the on-site equipment and operations. In this particular case, the equipment required at the proposed 1-23 plant site would be almost the same under both the Chancellor and Amerada options. Consequently, the environmental impacts, if any, of both proposals would be similar. The Board finds that environmental concerns would not favour one proposal over the other and would not constitute the sole reason for accepting or denying either proposal.

5 ECONOMICS OF A NEW PLANT COMPARED TO USING AN EXISTING PLANT

Chancellor said that its proposal was in its best interests and more economic than the alternative put forward by Amerada to process the gas at its 6-18 plant. The comparison of capital costs submitted by Chancellor indicate that the overall difference is $190 000. The major differences between the two options was the need for a refrigeration facility in the Chancellor option and higher pipeline costs in the Amerada option. Neither party identified significant cost differences for compression, well sites, or the gas gathering system.

With respect to the sales/transfer line that would be required for the Chancellor and Amerada options respectively, Chancellor stated that a sales line to the south of its plant would be a 101.6 millimetre (mm) line and would require secondary road crossings every 2.12 km and no major highway crossings. Transporting its gas to the Amerada plant would require a 152.4 mm line and secondary road crossings every 1.6 km and a major highway crossing for Highway No. 2. Chancellor argued that the larger line would be required because it may have to transport both a gaseous and a liquid phase material and subsequently it would be more expensive. Amerada disputed the additional cost of the transfer line in its option stating that there was no need for a 152.4 mm line as stated by Chancellor because the gas that would be transported is very dry and would not contain large amounts of liquids.

Amerada stated that its offer to process Chancellor's gas for $7.10 per thousand cubic metres ($0.20 per thousand cubic feet) was most reasonable and should be given serious consideration by Chancellor. Chancellor stated that proceeding with its own facility would not involve process fees and thus the major difference in the economics for either option is whether or not a process fee is required. Chancellor also stated that proceeding with its own plant would yield a 27.0 per cent higher return on its investment than would the Amerada option. Amerada presented no evidence to refute Chancellor's statement about overall return on investment.

The Board considers the economics of the two options to be slightly in favour of Chancellor proceeding with its own plant. Although the capital cost differences are minor, the Board accepts the applicant's view that process fees involved in the Amerada option would make Chancellor's own plant more attractive to it.

6 OVERALL PUBLIC INTEREST

As mentioned earlier, in assessing the broad public interest of the opposing proposals, the Board must have regard for a number of factors, not just the fact that existing plant capacity is available in the area. Public objections to the application and environmental impacts are very significant factors which must be evaluated. In this case, these two matters are clearly not issues that affect the broad public interest and certainly could not be used to deny the Chancellor application. With respect to the economics of and potential returns to the province of the two proposals, there was no clear evidence to show a substantial advantage of the Amerada proposal over the Chancellor proposal. The evidence in fact shows a slight advantage for the Chancellor proposal.

7 CONCLUSION

The Board on occasion involves itself in the business decisions of oil and gas producers. This, however, would only occur when significant resource conservation, correlative rights, public, or environmental interests are of concern. In the absence of these concerns the Board does not believe that involvement is appropriate. In this case due to the combination of sweet gas, similar equipment requirements and land use, minimal environmental impacts, and the absence of public concerns, there are no compelling public interest issues which would dictate denial of the application. The Board therefore sees no reason not to grant Chancellor's corporate desire to process gas at its own facility.

8 DECISION

The Board confirms its approval of Application No. 921683, and subsequent issuance of Board Approval No. 7112 which remains in good standing.

DATED at Calgary, Alberta, on 19 May 1993.

ENERGY RESOURCES CONSERVATION BOARD

R G Evans

R. G. Evans, P.Eng.
Board Member

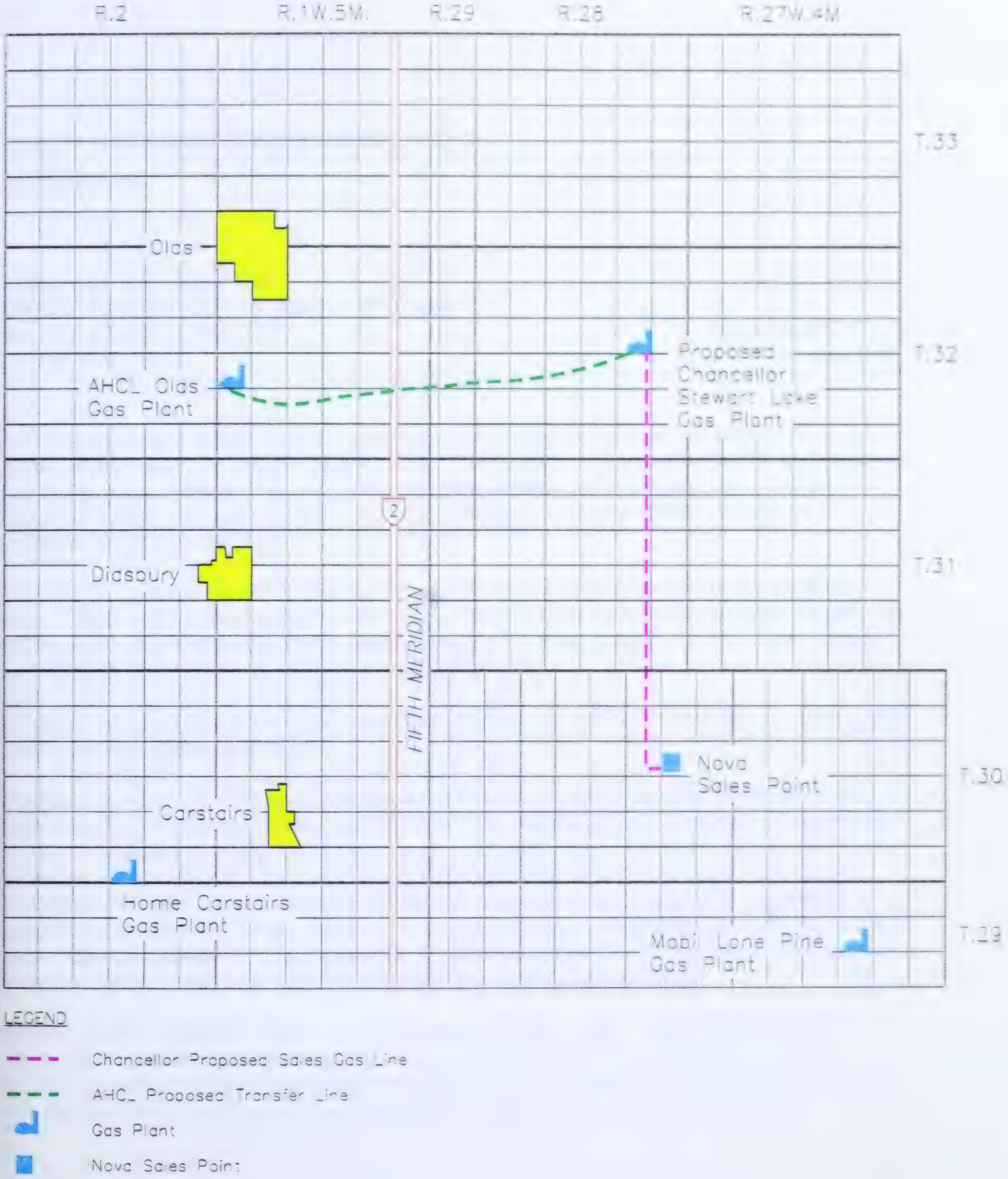
R. G. Paterson, P.Eng.*
Acting Board Member

J R Nichol

J. R. Nichol, P.Eng.
Acting Board Member

---

* R. G. Paterson was unavailable for signature but concurs with the contents and with the issuing of this report.



STEWART FIELD
Application No. 921683
Chancellor Energy Resources Inc.

D 93-6
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SHELL CANADA LIMITED
APPLICATION TO EXPAND BLOCK STORAGE AT
SHANTZ SULPHUR FACILITY
SW 1/4-35-31-4 W5M

Application No. 931014
Interim Decision D 93-7

Shell Canada Limited (Shell) applied to expand its existing sulphur block storage facilities at Shantz because of the collapse of world sulphur markets. A joint intervention opposing Shell's application was filed by Mr. Doug Jones and Mr. Jerry Dziadek. Consequently the Energy Resources Conservation Board (the Board) convened a hearing in Calgary, Alberta on 4 October 1993 to consider the application and the intervention.

Shell said it considered various options but did not find a more suitable alternative than expanding Shantz. Shell said that its proposal exceeds the normal Alberta Environmental Protection standards for facility design and monitoring. Shell reiterated the need for an early decision to allow it to construct the sulphur storage facilities to avoid inclement weather.

Mr. Jones and Mr. Dziadek were concerned about alternatives to avoid storing sulphur at Shantz, and about potential environmental effects.

The Board recognizes that the depressed sulphur market has resulted in the need for sulphur storage at production sites throughout the province. The Board has considered Shell's application from the point of view of suitability as a large volume storage site. In comparison to alternative sites in the region, Shantz has the advantage of having newly-built modern facilities in place and of not requiring the trucking of the large volumes of Caroline production. Potential environmental or social impacts do not appear to be any greater at Shantz than at other current sulphur production sites where displacement storage might be considered. The Board notes the stringent design features to prevent environmental impacts and monitoring program to promptly detect any possible adverse affects.

Regarding Shell's proposal to truck up to 1000 tonnes per day of sulphur from other plants in the region, the Board believes that any large scale truck transfers should be the subject of a separate application, considering the specific details and merits of such a transfer. Accordingly, at the current time the Board will limit the amount of transfers from other plants to 200 tonnes per day.

The Board hereby approves Shell's Application No. 931014 subject to the above condition. The Board will issue a further report in due course giving the reasons for the decision in greater detail.

DATED at Calgary, Alberta, on 15 October 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

R Keushnig

H. R. Keushnig, P.Eng.
Acting Board Member

K. G. Sharp, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SHELL CANADA LIMITED
APPLICATION TO EXPAND BLOCK STORAGE AT
SHANTZ SULPHUR FACILITY
SW 1/4-35-31-4 W5M

Decision D 93-7
Application No. 931014

1 INTRODUCTION

1.1 Application

Shell Canada Limited (Shell) received Board Approval No. 6319 on 15 October 1990 for a sour gas plant near Caroline and for associated sulphur storage and handling facilities at Shantz in SW 1/4 of Section 35, Township 31, Range 4, West of the 5th Meridian. At that time Shell said it hoped to avoid storing any sulphur in block form at Shantz, but applied for and was given approval to store up to 630 thousand tonnes in block form in the event of severe and extended disruptions to its normal sulphur shipping and marketing.

Production start up of the Caroline gas plant and the Shantz sulphur facility occurred in February 1993. Very soon after, as a result of a severe decline in world demand for sulphur, Shell found it necessary to commence sulphur block storage at the initially approved site. It became apparent that considerable additional block storage would be required and hence Shell applied to expand its sulphur block storage area at Shantz. Shell anticipates that the existing sulphur storage capacity will be used up by January 1994 and an additional capacity of up to 1.87 million tonnes will be needed by May 1995. Shell also stated that further sulphur block storage may be needed in the future should depressed sulphur market conditions persist beyond mid 1995. Shell also requested permission to truck up to 1000 tonnes per day (t/d) of sulphur from other sulphur producing plants in the region for storage at Shantz.

1.2 Interventions

Shell's application was advertised for objections on 12 August 1993. A joint intervention was received from Mr. Doug Jones and Mr. Jerry Dziadek. Mr. Dennis McIvor also submitted an intervention.

1.3 Hearing

The application was considered at a public hearing in Calgary, Alberta on 4 October 1993, by Board Member J. P. Prince, Ph.D. and Acting Board Members H. R. Keushnig, P.Eng., and K. G. Sharp, P.Eng. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principles and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) John E. E. Lowe	L. E. Auger, P.Eng. D. L. Duncan, P.Eng.
D. Jones J. Dziadek	D. Jones J. Dziadek
Energy Resources Conservation Board staff E. P. Moeller, R.E.T.	

Mr. D. L. McIvor did not respond to the Notice of Hearing and did not appear at the hearing. The Red Deer Regional Planning Commission submitted written comments on the application but did not appear at the hearing.

2 INTERIM DECISION

Following the hearing, the Board issued an Interim Decision on 15 October 1993 approving Shell's application to store additional sulphur at Shantz, subject to initial restrictions on trucking of sulphur into Shantz. The interim decision was released to accommodate Shell's concerns about construction difficulties in winter weather conditions.

3 ISSUES

The Board believes that the issues are:

- need for additional sulphur storage,
- options to storing sulphur at Shantz,
- environmental impacts of storing sulphur at Shantz, and
- future storage needs and transfer of sulphur from other plants.

Need For Additional Sulphur Storage

Shell stated that its application to store sulphur at Shantz is the result of prolonged deterioration of world sulphur markets that was not anticipated at the time of the Caroline hearing. The applicant said that it is also pouring sulphur to block at its other plants in the province. Shell expects to sell only about 35 per cent of its sulphur production this year due to the world surplus of sulphur. Its only options to storing sulphur at Shantz are to shut down the Caroline gas plant or to find another site to store sulphur. Shell said that storage of sulphur at Shantz was discussed at the Caroline hearing, although at the time it did not foresee the extent of sulphur storage that would be required due to the downturn in marketing opportunities.

Shell stated that its application is for approval to install additional sulphur storage facilities capable of holding up to 1.87 million tonnes of incremental sulphur that could be produced and sent to Shantz by mid 1995. Shell indicated that the volume includes trucking of up to 1000 t/d of sulphur into Shantz from other sulphur production facilities if needed. The applicant said that it would continue to pursue markets for its sulphur and anticipated that markets for the product should improve by mid 1995. Shell also said that it could not guarantee the markets would improve and therefore a possibility existed that it may have to apply in the future to further increase sulphur storage capacity at Shantz. It estimated that the ultimate capacity of the Shantz site would be 10 million tonnes of sulphur.

The interveners expressed concern about Shell's inability at the time of the Caroline hearing to accurately forecast sulphur markets. The interveners were also concerned that the Shantz site would be used to store additional sulphur trucked in from other gas plants. The additional sulphur would exacerbate their concerns about the impact of long-term sulphur storage.

The Board acknowledges the interveners' concerns about sulphur block storage at Shantz. However, the issue of what to do with the sulphur is part of a worldwide over-supply problem. Sulphur producers throughout Alberta and elsewhere are experiencing difficulty in marketing sulphur and consequently have to make decisions on storage of the product. The Board believes that the Shell application must be viewed in light of all other sulphur producers facing storage needs. The Board also notes that sulphur production from Shell's Caroline plant is significant, in the order of 23 per cent of total gas plant sulphur production in Alberta. The Board does not believe that Shell's application to expand Shantz breaks commitments made by Shell at the Caroline hearings. Shell hoped to avoid having to block sulphur at Shantz, but it did allow for the possibility.

The Board is satisfied that there is a need for additional sulphur storage at the Shantz complex.

Options To Storing Sulphur At Shantz

Shell said that it supplies all of its offshore sulphur markets from Shantz in order to minimize sulphur storage at the site. Shell stated that its North American market needs are met primarily by sulphur production from its Waterton gas plant because it has liquid sulphur handling and rail loading facilities in place. Shell said that the North American market is not large enough to absorb Caroline sulphur production, and installing liquid handling facilities at Shantz to serve that market would be expensive. Shell also indicated that it could face trade agreement restrictions by the United States if it tried to serve that market from Shantz.

Shell said that blocking sulphur at any of its other sulphur production sites (Jumping Pound, Quirk Creek, Crossfield) is not a good option because previous blocks at those sites have been reclaimed.

Shell said that it made a firm commitment not to store sulphur at the Caroline plant site and thus developed the Shantz site. Possible storage of incremental Caroline sulphur at Husky's Ram River (Strachan) gas plant would require the trucking of very large quantities of sulphur. Storage at any new currently undisturbed site would also require the same large volume of sulphur trucking and may cause other environmental impacts.

The interveners stated that no additional blocking of sulphur should be permitted at Shantz. They questioned whether Shell could minimize the need to store sulphur at Shantz by using Caroline sulphur production to fill North American markets and stockpiling the sulphur intended for export at other Shell operated storage areas, such as Waterton, which currently supply the North American market. The interveners expressed concerns about the possibility of sulphur from other gas plants in the province being trucked into Shantz, and thereby increasing the storage requirements and raising the potential for adverse environmental impacts. The interveners suggested that Shell install facilities that would allow it to ship liquid sulphur by rail to the North American markets thereby reducing the amount of sulphur storage that would be required in block form at Shantz.

The Board believes that efforts to store large amounts of Caroline sulphur away from the Shantz site could transfer the question to other locations less suited for sulphur storage and handling than the Shantz complex. In comparison to alternative sites in the region, Shantz has the advantage of having newly-built modern facilities in place, and not requiring the trucking of large volumes of Caroline sulphur because facilities exist to transfer Caroline sulphur by pipeline to the Shantz site. The Board concludes that there are no attractive alternatives to storage at Shantz.

Environmental Impacts Of Storing Sulphur At Shantz

Shell said that Shantz was chosen because of its proximity to a rail line, and on the basis of suitable geotechnical and topographic features of the site. Shell said that its Shantz development includes use of paving, synthetic liners to contain sulphur, use of specialized procedures for pouring of sulphur, detection systems for monitoring the integrity of runoff water, collection pond liners, groundwater monitoring, degassing of sulphur prior to it entering the Shantz complex, air quality monitoring, soil monitoring, and plans to melt the stored sulphur in the future using in situ melting devices to minimize generation of sulphur dust. Additionally, Shell stated that it has conducted extensive community awareness and information programs to allow the public to be aware of its plans and development procedures. The applicant indicated that it planned to continue meeting with and providing information to the public.

The interveners expressed concern about the features employed in sulphur base-pad construction, surface runoff water handling facilities, odour potential, sulphur dusting potential, block fires, and safety. They claimed that the devices proposed by Shell may not adequately protect the environment. Mr. Jones proposed that a geotextile liner be included in the base-pad design to provide additional protection against rock penetration. He also expressed concerns about truck traffic and noise in the event that sulphur would be trucked to Shantz from other locations.

The Board believes that the environmental impacts of the Shantz facility will be minimized by the environmental protection features incorporated in the planning and design of the Shantz complex. These features are state of the art for the handling, forming, and storage of sulphur in a safe, efficient, and environmental protective manner. The Board notes that Alberta Environmental Protection (AEP) has issued Clean Air and Water Licences to the Shantz development and that AEP has not specified the need for a geotextile liner. The Board understands that the measures in place for protection of the environment at Shantz exceed normal standards for construction and operation of sulphur storage. The Board therefore believes that installation of a geotextile liner in this case is not necessary.

Future Storage Needs and Transfer of Sulphur From Other Plants

Shell anticipated that the storage requested in this application would meet its needs until mid 1995. However, Shell said that there is a possibility that it may have to apply for a further increase in sulphur storage capacity at Shantz, depending on future sulphur markets. If this was necessary, it would be on Shell-owned land adjacent to the existing facilities.

As part of its current application, Shell wishes to truck up to 1000 t/d of sulphur to Shantz from the Jumping Pound, Quirk Creek, and East Crossfield plants because of limited block storage capabilities at these plants. These plants would be required to meet the Shantz sulphur degassing criterion of 10 parts per million of hydrogen sulphide. Road traffic and community concerns would be considered in the specific plans.

The interveners expressed concern about how much sulphur could be trucked to Shantz and the ultimate amount of storage at Shantz. They suggested that environmental and social impacts will increase if the amount of storage increases.

The Board believes that additional storage at Shantz, beyond that of the current application, could be suitable. However, this would be considered in light of future needs as they arise and the actual performance of storage operations to that point.

Regarding the trucking of sulphur to Shantz from other plants, the Board is satisfied that the Shantz site would be suitable for volumes up to 1000 t/d as proposed by Shell. However, the Board believes that any large volume transfer from one site to another should be considered on an individual basis, in order to weigh the relative benefits and impacts of trucking to Shantz versus storage at the originating plant or other dispositions, and to allow directly affected parties to express their views. Not enough evidence was presented at the hearing for the Board to make this determination for the source plants listed in Shell's application. The Board therefore has chosen to restrict trucked-in sulphur to 200 t/d until application is made to increase this based on the merits of the specific proposed transfer.

5 DECISION

The Board believes that block storage of sulphur at Shantz can be increased, given the protective measures to be implemented by Shell. The Board hereby approves Shell's application No. 931014 to increase sulphur block storage at its Shantz sulphur forming facility. Trucking of sulphur from other plants to Shantz is limited to 200 t/d at the current time, but may be increased upon successful application as discussed above.

Dated at Calgary, Alberta, on 5 January 1994.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Board Member

HR Keushnig

H. R. Keushnig, P.Eng.
Acting Board Member

K. G. Sharp, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

RANCHMEN'S RESOURCES LTD.
REOPENING OF HEARING OF APPLICATION NO. 901312
APPLICATIONS FOR
•APPROVAL TO CONSTRUCT AND OPERATE WELL SITE FACILITIES
• PERMITS TO CONSTRUCT PIPELINES
KNOPCIK FIELD

Decision D 93-8
Applications No. 901312,
931123, 931124,
931125 and 931149

1 INTRODUCTION

1.1 Applications

On 3 March 1993 Ranchmen's Resources Ltd. (Ranchmen's) advised the Energy Resources Conservation Board (the Board) of their intention to resume operations at the well, Ranchmen's et al Knopcik 7-19-74-11 (the 7-19 well) by way of a copy of a letter sent to Mr. R. L. Boonstra (the interveners). The well was the subject of a Board hearing held 27 September 1990 and was approved for certain operations by the issuance of Decision Report D 90-16. The decision stated the hearing would be reopened if testing confirmed the well should continue to operate and if the interveners so desired. The Board was advised in writing on 24 March 1993, by the interveners, that they did want to reopen the hearing into the continuing operation of the well.

Subsequent to the interveners request to reopen the hearing, Ranchmen's applied for approval to construct production facilities at the 7-19 well site, for permits to construct a sour gas pipeline, a sweet gas pipeline and a fuel gas pipeline from surface location 7-19-74-11 W6M to existing pipelines operated by AEC Oil and Gas Company Ltd. (AEC) at surface location 5-12-74-12 W6M.

1.2 Hearing

A public hearing of the applications was held on 6 October 1993 in Grande Prairie, Alberta, before a division of the Board comprising of Board Members J. P. Prince, Ph.D. and N. G. Berndtsson, P.Eng. and Acting Board Member, W. G. Remmer, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Ranchmen's Resources Ltd. (Ranchmen's) A. G. MacWilliam	T. D. Brooker, P.Eng. B. R. Cumming, P.Eng.
Adjacent Landowners (Interveners) Rev. W. A. Ludwig	Mrs. M. L. Ludwig Mr. B. D. Ludwig Mr. F. R. Ludwig Mr. W. R. Ludwig

THOSE WHO APPEARED AT THE HEARING (con't)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Adjacent Landowners (Interveners)	Mrs. K. L. Ludwig Mrs. D. L. Ludwig Mr. J. Ludwig Mrs. H. A. Schiltuis Mrs. R. P. Ludwig Miss M. L. Ludwig
Energy Resources Conservation Board staff N. F. Lord, C.E.T. A. P. Chare	

2 BACKGROUND

On 3 May 1990 Ranchmen's applied to the Board for a licence to drill the 7-19 well. The application was processed routinely by Board staff and Well Licence No. 0144089 was issued on 7 May 1990.

After the well was drilled and cased, but before it was completed and tested, the Board was advised that the drilling of the well had proceeded against the wishes of the interveners. Upon being notified of the situation, Ranchmen's suspended the well pending a review of the well licence.

A public review of the well licence was held at the offices of the Board in Grande Prairie, Alberta, on 27 September 1990.

During the hearing Ranchmen's submitted that it had originally proposed to drill the well in the north-east quarter of Section 19-74-11 W6M. This quarter section is owned by the interveners, who made Ranchmen's aware of their opposition to the well. Upon re-evaluation of the geology, Ranchmen's concluded it could drill a successful well from a surface location in the south-east quarter of Section 19, and believed that relocating the well would alleviate the concerns and objections of the interveners.

The interveners originally raised their concerns regarding the proposed well in the north-east quarter of Section 19 with Ranchmen's and Board staff in the Grande Prairie office in March of 1990. The interveners submitted that the relocation of the well site to the south-east quarter had not alleviated their concerns and objections.

As a result of the hearing, the Board accepted that Ranchmen's, as holder of the mineral lease for Section 19, had the right to explore for and develop any reserves which may underlie the section.

The Board also recognized that, during the drilling of the well, the interveners may have experienced some negative impacts from noise, dust, and traffic. However, given that the drilling of the well proceeded routinely and without incident, the Board expected that these would have been no more than a general nuisance and inconvenience.

Following the hearing the Board found that, in order to obtain sufficient evidence to reach a decision respecting the well, the well would have to be completed and tested, and recommended the following conditions be adhered to:

- Procedures should comply with the criteria set out in Interim Directive ID 90-1, Completion and Servicing of Sour Wells.
- Ranchmen's should comply with all criteria set out in the Sour Gas Flaring Permit for the well, issued from the offices of the Board on 31 July 1990.
- An Emergency Response Plan (ERP) which encompassed the interveners residences should be prepared.
- The well site should be manned on a 24-hour basis during completion and testing operations.
- Ranchmen's should inform the Board and the interveners as to Ranchmen's position with respect to the abandonment, suspension, or production of the well as soon as practical after completion of testing.

Subsequently to the decision report being issued, Ranchmen's tested the well, from the Halfway zone, from 6 December to 19 December 1990 and from 6 January to 25 January 1991. The testing proceeded without incident or complaint, with the exception of a minor failure in the testing equipment on 23 January 1991. On that date, a low pressure separator gauge glass burst, releasing an estimated volume of 60 m^3 of raw gas to the atmosphere. The well was shut in within 3 minutes of the failure and H_2S monitoring was conducted. A peak single reading of 8 ppm H_2S was detected 200 metres east of the testing equipment as a result of the failure.

At the conclusion of the testing operation, Ranchmen's secured the wellhead by chaining and locking all valves and bull plugged all other openings. The well has remained as a capped gas well since that time.

3 ISSUES

The Board considers the issues with respect to the applications to be

- the need for the well, production facilities and pipelines,
- the testing of a second, potentially productive zone in the well,
- the impact of the well, production facilities and pipelines,
- the safe operation of the facilities, and
- communications among all parties.

4 CONSIDERATION OF THE APPLICATION

4.1 Views of the Applicant

Need For the Well and the Associated Production Facilities and Pipelines

Ranchmen's submitted that the need for the well was unchanged since the previous hearing and, in fact, had been strengthened by the results of its testing the Halfway zone which had established proven reserves in commercial quantity.

Having confirmed their need for the well and having established proven reserves, Ranchmen's submitted that the applied-for production facilities and related pipelines were needed to develop those reserves and bring them to market. Ranchmen's stated that it had obtained the consent of the landowner on which the production facilities were to be located, and that all land owners and surface occupants along the proposed pipeline route had agreed to the pipeline routing. Ranchmen's submitted that it had agreements with AEC for the operation of the production facilities and the transportation of the produced gas from the tie-in point at surface location 5-12-74-12 W6M to AEC's Sinclair gas plant at surface location 14-18-74-12 W6M. Ranchmen's further submitted that it had obtained firm commitment from Nova, Alberta Company Ltd. (NOVA) for transportation of sales gas on the NOVA system from AEC's gas plant commencing 1 November 1993.

Testing of the Jurassic Formation

With regard to the request to test a second, potentially productive zone in the well, in the Jurassic Formation (Jurassic) Ranchmen's stated that, to confirm the Jurassic's potential, a test of the zone would be required. If the Jurassic was found to be productive, the economics of the well would be further enhanced. Ranchmen's described the completion and testing operations for the Jurassic zone in detail and confirmed that it would follow standard oilfield testing practices during any testing. Ranchmen's stated that it believed the Jurassic to contain no H_2S, based on its review of nearby wells completed in the Jurassic. A gas analysis from the nearby well, Turbo et al Knopcik 13-01-74-11, which is presently producing from the Jurassic, was submitted to confirm the absence of H_2S. The completion and testing of the Jurassic would require 15 to 20 days, following which Ranchmen's would have the information required to confirm whether or not the sweet gas pipeline and related sweet gas production facilities would be required.

Impacts of the Well, Production Facilities, and Pipelines

With regard to the impacts of the well, production facilities, and related pipelines Ranchmen's submitted that it felt that any negative impacts would be minimal. In order to help minimize the impact on the interveners, Ranchmen's committed to move the well site access road, to the west side of the lease. Ranchmen's has acquired an easement and has surveyed for a new access road, which would enter the lease from the west side. At present the access road enters the well site from the east, bordering the southern boundary of the interveners property. At the east end of the access road it joins a county road allowance that is also used by the Ludwigs for access to their property. Ranchmen's submitted that, by moving the road, potential traffic related problems such as noise and dust would be eliminated insofar as the interveners may be impacted. Ranchmen's also indicated that the proposed production facilities would be housed in small (10' x 8') metal buildings and believed that the buildings would not be visible from the interveners' residence due to the presence of a stand of trees on the north side of the quarter.

Ranchmen's also confirmed that a flare stack would be installed on the lease. The flare stack would be 12.2 metres in height to abide by ERCB regulations. However, the flare stack would not, under normal circumstances be lit, as it was intended only for infrequent depressuring operations at the well site. On those occasions when it was necessary to use the flare stack, it would be a manual operation with the flare being lit manually and the site manned continually while the operation took place. An emergency shutdown (ESD) valve would be installed in the line from the wellhead to the production equipment. The ESD valve would shut in the well automatically in the event that pressures, either higher or lower than preset limits, were reached. The ESD valve could also be shut remotely from AEC's gas plant, if necessary. In either case, the production from the well would not be directed to the flare stack. Operators from the plant would have to visit the well site to determine the reason for the ESD valve closure and, if appropriate, to manually put the well back in service. Under normal circumstances, the well site would be visited once per day by operators from the gas plant.

Safe Operation of the Facilities

With regard to safety considerations Ranchmen's submitted that the production equipment and pipelines had been designed to meet all safety requirements, such as the installation of the ESD valve, H_2S monitoring in the buildings, high and low pressure shutdowns, and the capability to remotely shut in the well if an alarm was received at the AEC gas plant. The sour gas pipeline is rated as a Level 1 pipeline, which is defined as one that has the potential to release less than 300 m^3 of H_2S. In this particular case the potential release is calculated to be 88 m^3, and would require no increased separation distance between it and any dwellings other than that required for the easement for the right of way. Ranchmen's submission confirmed that there are no dwellings, facilities or developments within the prescribed distance.

Ranchmen's confirmed that the well, production facilities, and pipelines would be included in AEC's ERP. For purposes of the ERP, the emergency planning zone for the well site was calculated to be 242 metres. The closest dwelling to the well is occupied by Mr. Benjamin Ludwig and family and is located 758 metres north-east of the well. At the hearing Ranchmen's committed to providing the Board with anticipated potential H_2S concentrations at the nearest dwelling, calculated using the same basis as that used for the emergency planning zone calculation. Subsequently, Ranchmen's provided the Board with that information which predicts a maximum H_2S concentration using a worst case scenario of gas release rate, wind speed, and direction. This worst case scenario predicts peak H_2S concentrations in the order of 3-15 ppm at the Ludwig's residence and, therefore, evacuation would not be necessary.

Communications

With regard to communications Ranchmen's stated that it had made every reasonable effort to communicate its plans for the well site to the interveners, but the interveners had refused all offers of communication. Ranchmen's stated that, initially it had attempted to communicate both verbally and in writing with the interveners. Ranchmen's submitted that it ceased attempting verbal communications when the interveners objected to such attempts and stated that any such attempts by Ranchmen's were considered to be harassment. Since that time all communication attempts had been in writing by way of double registered letters. However, the interveners had refused to accept mail delivery from Ranchmen's. Ranchmen's stated that it was prepared at any time to attempt to reopen communication with the interveners, but stressed that such communication would require the agreement of the interveners.

4.2 Views of the Interveners

Need for the Well and the Associated Production Facilities and Pipelines

The interveners stated that they saw no need for this particular well and suggested that the Board order its abandonment. The interveners reaffirmed their position at the previous hearing that the movement of the well from the proposed location on their land to an adjacent quarter had not alleviated their concerns and that Ranchmen's had been amiss in making such an assumption. They contended that there was adequate opportunity for the placement and drilling of wells, particularly sour gas wells, in areas of the province that were not subject to the problems associated with energy developments in close proximity to people.

The interveners had no specific view on the need for the production facilities and related pipelines, having contended that they saw no need for the well itself, but viewed the total production scenario as negatively affecting their beliefs and lifestyle.

Testing of the Jurassic Formation

With regard to the testing and completion of the Jurassic zone the interveners stated they had considerable concerns regarding the proposed procedures. In particular, the high pressures to be used to fracture the formation, prior to testing or putting on production, was of concern to them. By way of example, the interveners quoted from a story in the Edmonton Journal, in which residents in North-east British Columbia were reported as believing that an increased incidence of earthquakes in the area was linked to oil and gas operations.

Impacts of the Well, Production Facilities, and Pipelines

With regard to the impacts of the well and the proposed production facilities and pipelines the interveners submitted that both the drilling and original testing of the well had already caused adverse impacts on them. They stated that the presence of the well and production facilities plus other industrial intrusions, such as logging and pipelining, effectively frustrated options for them in attempting to develop a responsible Christian life style and Christian community. The interveners stated that considerable time, effort, and expenditures had been committed to develop a Christian community, and it was their hope that this could be achieved without any industrial intrusions of this nature. They also submitted that the presence of the well and related facilities would restrict the development potential of their property and would also infringe on their rights to privacy. The interveners further contended that allowing the well to be placed on production would add to the environmental problems caused by the burning of fossil fuel, citing as examples "the greenhouse effect" and global warming as resulting from fossil fuel use.

The interveners also submitted they had suffered unusual incidents with their livestock, at about the same time of the original testing of the well, in Spring 1991. They submitted that approximately 50 per cent of their sheep and goats had aborted during that time, which is an abnormally high percentage that has not occurred before that time or since. The interveners also stated that a local veterinarian contacted at the time, stated that pregnant animals, such as sheep and goats are susceptible to toxic gases. During that same period, the interveners stated that many of the community suffered from headaches and flu-like symptoms. At the time the incidents occurred, the interveners did not directly link the problems with the animals and the sickness felt by the community members specifically to the testing of the well. Since that time, however, the interveners have concluded that the testing of the well and their problems may in fact be connected. Their belief was strengthened when they learned about the incident of 23 January 1991 and the release of 60 m^3 of sour gas.

Following the drilling of the well, Mr. Benjamin Ludwig stated that the water well on his land had started to experience problems with foul odours. This is an intermittent problem with the water well which the interveners link to the drilling and completion operations at the 7-19 well.

The interveners also stated that the well and related facilities would impact them by way of increased traffic into the well site resulting in dust problems, increased noise and concern for their children and animals on the road. The interveners stated that, contrary to Ranchmen's statement, the well site can be seen from their property as the stand of trees, referred to by Ranchmen's, offers only a partial screening.

Safe Operation of the Facilities

With regard to safety considerations at the well site, the interveners submitted that the production from the well, containing 3.2 per cent H_2S, was lethal and that no safety measures could guarantee them 100 per cent safety. In fact, they contended that the presence of such safety measures and the existence of an ERP served to confirm the fact that the well was dangerous and life threatening.

Communications

With respect to communications, the interveners reaffirmed their position of not accepting mail or telephone calls directly from Ranchmen's which, in their opinion, represent harassment. They also stated that any communication regarding this matter should be directed through the Board and not from Ranchmen's directly.

4.3 Views of the Board

Need For the Well and the Associated Production Facilities and Pipelines

The Board accepts that Ranchmen's, as holder of the mineral lease for section 19-74-11 W6M, has the right to develop the reserves which underlie the section. The Board also accepts Ranchmen's evidence regarding the results of testing the Halfway zone, which establishes proven reserves in commercial quantities. Given this, the Board believes the well is needed to enable Ranchmen's to develop its reserves and would be prepared to approve it provided that the potential adverse impacts, after all mitigation efforts have been made, are not serious enough to justify denial.

With respect to the production facilities and related pipelines, the Board notes that all necessary consents and easements have been obtained by Ranchmen's from all applicable surface owners and occupants. The Board has reviewed Ranchmen's detailed submissions regarding the applied-for facilities and pipelines and concludes that the applications meet all of the Board's requirements. Given these facts, and no specific evidence in opposition from the interveners, the Board believes the need for the associated facilities has been established. The Board also notes that any approval or permit issued for these facilities would be subject to conditions designed to reduce negative impacts and that operations would be expected to be carried out in a manner consistent with good oilfield practices.

Testing of the Jurassic Formation

With respect to the completion and testing of the Jurassic zone, the Board notes that Ranchmen's tested the Halfway, which is sour, with no major incidents. The Board is satisfied that the testing of the sweet Jurassic zone is needed to establish the potential of the zone and to enable the applicant to finalize facility and pipeline designs. The Board notes that Ranchmen's plans for testing the Jurassic follows good oilfield practices and during the testing operation, the well site would be manned continuously. The Board concludes that the testing operations are required and should proceed as they do not represent a significant nuisance or hazard to the interveners.

Impacts of the Well, Production Facilities, and Pipelines

With respect to the impacts of the well, production facilities, and related pipelines on the interveners overall lifestyle, the Board recognizes the decision made by the interveners to choose a life style that attempts to insulate them from perceived negative aspects of society, in general, and of industrial intrusions in particular. The Board also notes there are numerous examples of coexistence between oil and gas operations and rural communities throughout the province, with minimal impact to the residents of such communities. The Board believes that such coexistence is possible through the use of effective planning, compliance with applicable regulations and effective communication among the parties. In this particular case, the Board believes that coexistence is possible but that it would require improved efforts at communication from both sides. The Board is prepared to assist the communication process as much as possible.

With regard to the interveners comments regarding the burning of fossil fuels, the Board notes that the province is developing an overall strategy, and that there are associated regulations applicable to industrial facilities which affect the emission of various substances to the atmosphere. This issue is complex, global in nature and the contribution of this well to the global problem is not significant enough to justify ordering its abandonment.

With respect to the impacts on livestock, the Board recognizes the concerns of the interveners, but notes there was no evidence submitted to directly link the problems with the livestock in Spring 1991 with either the testing operations of Ranchmen's or any other oilfield related operations. Moreover, the Board is not aware of any incident of releases, other than the 23 January 1991 incident. This release was of short duration and such a small volume that, with wind dispersion, H_2S odours would be barely detectable, if at all, at the Ludwig's residence. The Board also notes that the well has been shut in since the conclusion of the test, on 25 January 1991.

The Board acknowledges the interveners statements regarding the problems with the water well on their property. The Board notes that Ranchmen's agreed at the hearing to test the water well and expects Ranchmen's to comply, at the interveners convenience.

With respect to dust, noise, and traffic concerns the Board notes that Ranchmen's intend to relocate the existing lease road, to allow access to the well site from the west. The Board agrees that relocating the lease road will serve to mitigate problems relating to dust, noise, and traffic.

Safe Operation of the Facilities

The Board appreciates the interveners safety concerns and requires Ranchmen's to have in place procedures and equipment to prevent releases and, however unlikely a release may be, the company must also have an ERP in place to deal with public safety.

The Board notes that prior to drilling the well the H_2S concentration was estimated to be 8.7 per cent, based on the Doig formation, with a corresponding Emergency Planning Zone (EPZ) of 830 metres. Only one of the Ludwig's residences is within that distance, being approximately 758 metres from the well, but all of the community residences were included in the initial EPZ. However, well testing determined the H_2S concentration to be 3.28 per cent from the Halfway Formation, which reduced the EPZ to 242 metres. The Board notes that the Ludwig's community residences need not be included in the current EPZ but appreciates the caution exercised by Ranchmen's to include all of them. Based on the information submitted by Ranchmen's following the hearing, the maximum anticipated H_2S level at the closest residence is 3 to 15 ppm given a combination of the worst case release rate, wind speed, and direction. This concentration is lower than the mandatory evacuation of 20 ppm established by Alberta Health, and the Board therefore believes that, in the very unlikely event of a release occurring, it will have minimal impact on the interveners and will not be life threatening at their residence and evacuation need not occur. However, the Board also notes that ERPs require monitoring in the event of any release, which provides assurance that residents in the area are protected from higher levels of H_2S than predicted.

The Board also reviewed Ranchmen's submission with regard to the installation of emergency shut-down equipment (ESD valves, flare stack, and H_2S monitoring equipment) and notes this equipment

meets or exceeds requirements of the regulations and will add to the safety of the well.
The Board concludes that the use of the safety measures proposed, the ERP, and the remote possibility of even very low levels of H_2S at the nearest residence provides for the safe operation of the well and the applied-for facilities.

Communications

With regard to communications, the Board believes it is the responsibility of all parties to ensure that adequate and meaningful communications take place. For that to occur, all parties must participate in the dialogue. Ranchmen's initial communication attempts were inadequate, however, the interveners must also share responsibility as they have refused to cooperate. As a result they may not understand the degree of safety associated with this operation. The Board also notes that it is aware of several examples where objections have been resolved by moving a proposed well location off the interveners property, as was done in this case. The Board regrets that the interveners concerns were not initially addressed by the Board or Ranchmen's but, not withstanding that, the Board believes the continuing refusal of the interveners to participate in communication serves only to aggravate the current situation. The Board notes Ranchmen's stated position to be willing to continue communications with the interveners. The Board encourages the interveners to contact the Board regarding any concerns they may have with the operations at the well site. They also encourage the interveners to open communications with Ranchmen's to serve their mutual needs.

5 DECISION

The Board has carefully considered all the evidence presented and taken into account the concerns of the interveners. The Board has determined that the well can continue to operate, and the production facilities, and related pipelines can be operated safely and with minimum impact to the interveners.

Accordingly, the Board approves Applications No. 931123, 931124, 931125, and 931149. The appropriate documents will be issued in due course.

DATED at Calgary, Alberta, on 24 November 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

N. G. Berndtsson, P.Eng.
Board Member

W. G. Remmer, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR WELL LICENCE **Memorandum of Decision**
MOOSE MOUNTAIN AREA **Pre-Hearing Meeting**
HUSKY OIL OPERATIONS LTD. Applications No. 931689, 931696, 931746, 931747 and 931748

1 INTRODUCTION

Husky Oil Operations Ltd. (Husky) has applied to the Energy Resources Conservation Board (the Board) for well licences for five wells proposed to be drilled from surface locations in Lsd 2-23-23-7 W5M, Lsd 13-12-23-7 W5M, and Lsd 16-22-23-7 W5M. The wells would be known as HUSKY RIGEL MOOSE 10-14-23-7, 12-12-23-7, 10-22-23-7, 2-27-23-7 and 10-12-23-7. The purpose of the wells would be to explore the immediate area to obtain production from the Turner Valley Formation.

The Board was aware that a number of parties had concerns with these applications. To satisfy itself that parties which may be affected had the opportunity to set out their positions, the Board directed that the applications be advertised and a pre-hearing be meeting held to receive submissions as to the need for a public hearing. The notice issued by the Board noted that, if necessary, a hearing would be held on 11 January 1994 and submissions respecting the hearing were to be filed on or before 4 January 1994.

The pre-hearing meeting was convened at the offices of the Board in Calgary on 2 December 1993. The Board members presiding at the meeting were F. J. Mink, P.Eng., B. F. Bietz, Ph.D., P.Biol., and N. G. Berndtsson, P.Eng.

The names of the participants who registered at the meeting are shown on the attached list.

2 VIEWS OF THE APPLICANT

Husky submitted that it believed, based on the submissions already received, that the Board would find it was appropriate to hold a public hearing of its applications, and that the matter should proceed as advertised in the Board's notice. Respecting the need for further information, Husky noted that it was at risk. Husky advised that, as applicant, it would supply information it believed relevant to support its application. This information would be reviewed at the hearing and Husky would then be subject to the decision of the Board as to its adequacy. Husky submitted that all parties should be aware of and adhere to the Board's ERCB G-31, Guideline Respecting Applications For Local Interveners' Costs Awards, with respect to funding and intervener status.

Rigel Oil & Gas Ltd. (Rigel) supported Husky in its submissions relating to the matters considered at the pre-hearing meeting.

3 VIEWS OF THE INTERVENERS

The Wildlife Foundation (the Foundation) argued that the Board should decide at the outset of the meeting if it would require a public hearing. Further if a hearing was to occur, the Foundation felt it would be appropriate to reschedule the hearing to 25 January 1994 in order that the Foundation could properly prepare its submission. Besides some specific matters, its approach would be to review the application on an ecosystem basis by considering cumulative effects. The Foundation also requested that, irrespective of whether or not they made application for funds, they be recognized as an intervener.

The Rocky Mountain Ecosystem Coalition (the Rocky Mountain Coalition) supported the position by the Foundation that a hearing be held and that it be rescheduled to a later date in January in order that submissions could be adequately prepared by interveners. The Rocky Mountain Coalition submitted that as well as having specific concerns with the applications, it believed that cumulative effects and ecosystem management also must be addressed by Husky and the Board. This should be accompanied by an environmental impact assessment to acquire the appropriate baseline data sufficient to allow the Board to integrate the impacts of the specific project within a broader framework. The Rocky Mountain Coalition would also be seeking standing as an intervener at the hearing.

The Bragg Creek Environmental Coalition (Bragg Creek Coalition) submitted that as area residents they were concerned about the cumulative effect of the proposed development on the region. They also had specific concerns regarding public safety, impacts on wildlife habitat, and recreation, and the mitigative measures which should be applied. The Bragg Creek Coalition submitted that it would also be requesting intervener status.

Mr. Fred J. Fraser on behalf of the Old Sarcee Band, Uterus Clan (the Band) supported the request for a postponement of proceeding in order to allow sufficient time to arrange for the appearance of witnesses. The Band submitted that the impact caused by oil and gas activities on the environment was of great concern to them. To address their concerns the Band submitted that it was appropriate that the Board call for a public hearing for which they would be requesting local intervener status.

4 VIEWS OF THE BOARD

After considering the opening remarks of all participant parties the Board agreed that some of the interested parties may be affected by the application and the applications should be set down for a public hearing. The Board accepts the interveners arguments for rescheduling of the hearing and does not believe the modest extension requested would have an onerous impact on the applicant. The Board therefore intends to convene the hearing of these applications on 24 January 1994. Submissions to the Board must be filed no later than 17 January 1994. A notice of rescheduling will be issued in due course. The Board would expect that all parties observe the specified filing date and present all material which they wish to have considered at the hearing by this time. Material filed after this date may not be accepted for consideration at this hearing.

The Board would also confirm that all parties who presented positions at the pre-hearing meeting will be recognized to participate in the hearing.

Respecting matters of local interveners status and funding, the Board believes the appropriate procedures are set out in the Board's document G-31, Guideline Respecting Application For Local Interveners' Costs Awards and will rely on this mechanism to address the issue. In the interests of conducting an orderly hearing, the Board encourages parties with similar interests to work cooperatively in addressing issues.

With regards to the scope of the hearing, the Board accepts the Husky position that it is the applicant which must supply the appropriate material to support its applications. The Board will rely on this material to determine its adequacy in supporting the applications and therefore, it is the applicant which is at risk if insufficient evidence is provided. In turn, the Board also expects interveners to ensure that their submissions are of relevance to the applications and to the legislated mandate of the Board.

DATED at Calgary on 9 December 1993.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

N. G. Berndtsson, P.Eng.
Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Representatives
Husky Oil Operations Ltd. (Husky)	F. M. Saville S. Purcell
Rigel Oil & Gas Ltd. (Rigel)	K. F. Miller
The Wildlife Foundation (the Foundation)	Dr. B. L. Horejsi
Rocky Mountain Ecosystem Coalition (the Rocky Mountain Coalition)	M. Sawyer
Old Sarcee Band, Uterus Clan (The Band)	F. J. Fraser
Bragg Creek Environmental Coalition (Bragg Creek Coalition)	C. G. Docken
Energy Resources Conservation Board staff	R. D. Heggie R. Creasey, P.Biol. N. F. Lord

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

HOME OIL COMPANY LIMITED
IMPERIAL OIL RESOURCES LIMITED **Decision Report D 93-9**
RENAISSANCE ENERGY LTD. **Applications No. 931497, 931498, 931499, 931500, 931506**
APPLICATIONS FOR WELL LICENCES **Application No. 931671**
AND PIPELINE PERMITS **Applications No. 931467, 931468, 931469, 931470, 931471,**
COLD LAKE, LEISMER AND LEMING FIELDS **931501, 931670, 931502, 931503, 931504**

1 INTRODUCTION

1.1 The Application and Interventions

Home Oil Company Limited (Home), Imperial Oil Resources Limited (Imperial) and Renaissance Energy Ltd. (Renaissance) applied to the Energy Resources Conservation Board (the Board) for approval to construct pipelines and for well licences for a number of locations in Northeastern Alberta.

These applications were opposed by trappers who hold trapping permits in the area of application.

A public hearing of the applications was held in Grande Centre, Alberta on 25 November 1993 before a division of the Board comprised of Board Member, N. G. Berndtsson, P.Eng., and Acting Board Members R. N. Houlihan, P.Eng. and H. O. Lillo, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Home Oil Company Limited (Home) D. A. McCoy	D. Parker S. Reed B. Trottier D. White, P.Eng.
Imperial Oil Resources Limited (Imperial) R. W. Graw	R. Eccles A. Kennedy G. Ritchie, P.Eng.
Renaissance Energy Ltd. (Renaissance) M. Hurt	L. Skaien
B. Duckett (Mrs. Duckett)	
R. Strayer (Mr. Strayer)	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Environmental Protection F. Neuman B. Rippin	
Energy Resources Conservation Board P. Angrave N. F. Lord	

2 ISSUES

The Board considers the issues with respect to the applications to be

- the need for the wells and pipelines,
- the impacts of the wells and pipelines, and
- other matters.

3 CONSIDERATION OF THE APPLICATIONS

3.1 View of the Applicants

Renaissance submitted that objections to its applications had been withdrawn, with the exception of one application for a pipeline permit. Renaissance requested that the unopposed applications be approved. Renaissance submitted that in its discussions with the trappers no specific impacts had been identified for Renaissance to address. Additionally, in response to a question, Renaissance confirmed that the ERCB process was used to exact compensation. It requested that the outstanding application be held in abeyance pending the completion of a survey of the proposed route. The survey was necessary in the resolution of the concerns of Mrs. Duckett whose trapline is crossed.

Imperial applied to the Board for a well licence for the proposed well IMP MARIE "A" COLDLK 1-5-65-2. The purpose of the well is to determine the potential of a brackish water aquifer as a water source for the Imperial Cold Bitumen Recovery Project (the Cold Lake Project). Imperial stated that the use of brackish water is attractive because of its potential reliability and, as it is a non-potable source of water, it is environmentally preferable. Currently Imperial is using water from local groundwater aquifers which is a concern to local area residents. It believes the proposed well and information gleaned from it could alleviate this situation.

Imperial stated that the well would be drilled from an existing well site and no additional pipelines would be required. As only an additional area of approximately two hectares would have to be cleared, Imperial does not believe this would have significant impact. Imperial recognized that disturbance would occur during the drilling phase but this would be for a duration of seven to ten days.

Home submitted that its proposed wells and associated pipelines were required to offset a competitive drainage situation for Home's Leismer East Gas Unit No. 1. If these infill wells were not allowed to proceed the unit would not be able to produce its fair share of the remaining recoverable gas reserves from the Clearwater Formation.

Home submitted that the drilling of the proposed wells and construction of the pipelines would not likely pose any more environmental risk than other such activity in the area. Once the wells had been drilled and tied-in, they would normally require inspection approximately once during the winter season. The area would be limited to winter access and no permanent all-weather roads would be required. Based on these factors and as the area was already developed, Home did not believe significant impacts would occur from the proposed additional developments.

Home stated it had made numerous attempts to discuss the proposed development and possible specific impacts with Mr. Young on whose trapline some of the proposed development would occur but Mr. Young would not discuss specific impacts. Home stated it was prepared to implement mitigative measures such as limiting access to the site. In Home's opinion Mr. Young's primary concern was one of compensation which it believed could be addressed through the Trappers' Compensation Board.

Home stated that its activity is impacted by restrictions imposed by Alberta Environmental Protection, Fish & Wildlife Division, which prohibits oil and gas activity between 15 January 1994 and 30 April 1994 to protect caribou herds. If the project did not proceed before mid January 1994 it would have to be postponed until the next winters' drilling season. This delay would jeopardize the development.

3.2 Views of the Intervener

Although Mr. Young was present just before the commencement of the hearing to file a written submission he was unable to stay due to work commitments. Mr. Young declined the Board's offer to have Home's applications heard at an evening session of the hearing. Mr. Young submitted that the time of the hearing was not convenient for him. Additionally, Mr. Young did not believe that a site specific hearing could address his concern which was one of cumulative impacts on his activities and lifestyle as a trapper. Mr. Young submitted that to gain the information required to determine the cumulative effects of oil and gas activities an environmental impact assessment should be done. Afterwards a public hearing should be called to address his concerns.

Mrs. Duckett submitted that she was not prepared to address site specific concerns nor applications as sufficient time had not been allotted prior to the hearing. Mrs. Duckett requested a postponement of the hearing to provide her time to acquire the appropriate information to address the impacts of the proposed Imperial well. Mrs. Duckett also stated that an environmental impact assessment was needed to determine cumulative impacts of industrial activity including the effects of the wells and pipelines proposed in the applications in front of the Board. She believed this assessment should cover Northeastern Alberta and would be best carried out by the appropriate government department.

Mrs. Duckett contended that oil and gas industry operations had an adverse impact on the lifestyle of the trappers and the trapping activity itself. In response to a question on measures that could be taken to mitigate effects of oil and gas activities on trapping, Mrs. Duckett submitted that in the final analysis the impacts could only be mitigated through compensation. Mrs. Duckett stated her objections to the Imperial application would remain in place unless Imperial was to bargain with the same sensitivity as all other applicants who have proposed industrial activities on lands where her registered traplines are. In response to questioning, Mrs. Duckett stated that resolution of trappers compensation issues in the heavy oil and oil sands areas was not possible through the Trappers' Compensation Board. Instead trappers made special compensation arrangements with developers. She noted that for twelve years every other applicant had adhered to a compensation formula referred to as an impact assessment and have compensated accordingly. Mrs. Duckett stated she had requested the Board hold a hearing in 1991 to address her concerns and she had placed a blanket objection to development on her traplines. The hearing should consider cumulative effects with data from a full environmental impact assessment being presented.

Although, Mr. Strayer was not at the hearing to intervene to any specific application, he submitted some overall comments. Mr. Strayer supported the concept of the need for an environmental impact assessment and a cumulative approach to impacts on a regional basis and stated that he had extensive information on activities in the area.

3.3 View of the Board

The Board notes that with the one exception the applications by Renaissance were not contested at the hearing and understands that the trappers' objections were resolved by compensation. Further the Board understands that compensation has not been settled for the application that Renaissance has asked be held in abeyance.

The Board recognizes Imperial's submission respecting the benefits of brackish water as an alternative water source for the Cold Lake Project. The Board agrees that the proposed well is required to further investigate brackish aquifer deliverability. The Board understands that there are public concerns with the use of fresh water in the recovery of bitumen and agrees with Imperial that the use of brackish water may be environmentally preferable.

Respecting the impacts of the proposed Imperial well the Board notes that little additional surface disturbance would occur and no additional pipeline right of way would be needed. Given this the Board does not believe there will be a significant additional impact to the environment or to trapping in the area if the well is allowed to proceed. The Board acknowledges that some disturbance would occur during drilling, however, this would be limited to about a ten day period.

The Board notes that the need for the Home wells and associated pipelines was not challenged at the hearing. The Board accepts Home's position that there is a need for the wells to offset a competitive drainage situation. The Board accepts that a development infrastructure exists in the area already and does not believe that the additional facilities proposed will cause a significant additional impact. The Board acknowledges the applicant's undertakings to utilize existing rights of way where possible to reduce disturbance. The Board also notes that once drilling, completion, and tie in activities have been completed the operation of the system will require minimal access. The Board also notes that Home is required to comply with conditions imposed by Alberta Environmental Protection through the Mineral Surface Lease and not impact caribou migration in the area.

The Board notes that for the Imperial and Home applications few if any specific impacts were identified by the interveners which the applicants could address. The Board does not believe that either Imperial's or Home's proposed developments pose impacts that would cause the Board to deny the applications.

4 OTHER MATTERS

The interveners raised the matter of Environmental Impact Assessments for the proposed developments and the need for a regional study to address cumulative impacts of industrial activity on trapping. Home pointed out that the Alberta Environmental Protection Enhancement Act, lists certain activities that require an Environmental Impact Assessment. Oil and gas wells and pipelines are not included on that list. The Board does not believe it is necessary to have a broad regional study to consider the applications at hand. The Board outlined in its 4 November 1993 letter to the concerned trappers that site specific applications would be considered at the formal hearing. Given this the panel believes that sufficient time was allotted to allow parties to prepare for the hearing and as such the panel was not prepared to postpone the proceedings.

Imperial submitted that it was prepared to coordinate and was in fact in the process of commencing a study in the Cold Lake area of cumulative impacts on trapping resources. This study is to be conducted over the winter months and completed in May of 1994. Imperial hoped that all stakeholders such as trappers, government, and industry would participate in the study. Renaissance said it would be participating in this study. Home submitted that it saw merit in such a process but as yet had not committed to participate.

Mrs. Duckett submitted that a cumulative impact assessment was required, however it should be conducted by the appropriate government agencies and as such Mrs Duckett was not prepared to participate at this time. Mr. Strayer supported the concept of the study and would consider participation.

The Board believes that with broad stakeholder participation such a study could fulfil the objectives set out by concerned trappers in the area. Within a multi-stakeholder group the trappers themselves could assist in defining and setting out the scope and terms of reference of the study. The Board supports the Imperial initiative and believes that all interested stakeholders should participate. There would be benefit to all parties if area trappers were to participate in the study.

The Board would also point out that it is not the policy of the Board to entertain blanket objections, such as submitted by Mrs. Duckett, as the Board must deal with the site specific applications submitted to it.

Having considered the written submissions and the evidence presented at the hearing the Board cannot help but conclude that compensation is the major issue behind the objections. As acknowledged, this is not within the Board jurisdiction to consider.

The Board acknowledges the submission and statements of Alberta Environmental Protection pertaining to the Trappers' Compensation Board. The Board accepts that this is the forum to address compensation issues as they pertain to trapping. The Board also notes that a representative of the Alberta Trappers' Association has a seat on the Trappers' Compensation Board. Area trappers not satisfied with the action of the Trappers' Compensation Board therefore have a mechanism in place to deal with concerns voiced. The Board will advise the Trappers' Compensation Board of matters brought up at this hearing and of the initiative to be undertaken by Imperial and would urge it become involved.

5 DECISION

The Board concludes that there is need for the wells and pipelines and the Board does not believe that significant impacts will occur from these activities. Therefore, the applications should be approved and well licences and pipeline permits be issued in due course.

DATED in Calgary, Alberta on 22 December 1993.

N. G. Berndtsson, P.Eng.
Board Member

R. Houlih

R. N. Houlihan, P.Eng.
Acting Board Member

H. O. Lillo

H. O. Lillo, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR A WELL LICENCE
PORCUPINE HILLS-WHALEBACK RIDGE AREA
AMOCO CANADA PETROLEUM COMPANY LTD.

Memorandum of Decision
Pre-Hearing Meeting
Application No. 931598

1 INTRODUCTION

Amoco Canada Petroleum Company Ltd. (Amoco) has applied to the Energy Resources Conservation Board (the Board) for a well licence for a well proposed to be drilled on a surface location in Lsd 9-18-11-2 W5M. The well would be known as AMOCO HUNTER CREEK 10-18-11-2 and would be for the purpose of obtaining production from the Mississippian System. The well would be located in an area of south-western Alberta known as the Whaleback Ridge.

The Board was aware that a number of individuals and interest groups had concerns about the drilling of a well in this area and were requesting that a public hearing be held to address the application. To ensure all parties had an opportunity to set out their position, the Board convened a pre-hearing meeting to receive submissions respecting issues related to the application. The meeting was held at the offices of the Board on 14 December 1993. The Board members presiding at the meeting were J. P. Prince. Ph.D., R. G. Evans, P.Eng. and N. G. Berndtsson, P.Eng. The following major topics were discussed:

1. the location of the hearing,
2. the timing of the hearing,
3. the scope of the hearing, and
4. funding for local interveners.

The names of the participants who registered at the meeting are shown on the attached list.

2 VIEWS OF THE APPLICANT

Amoco stated it would defer to the wishes of the Board and local area residents respecting the location of the hearing. Amoco submitted that the hearing should commence no later than 28 February 1994.

Amoco submitted that the hearing should focus on the proposed well and not be expanded in scope to speculate on future applications since the results of the proposed well would be of paramount importance in determining what development might be proposed in the future. Amoco believed that it had already addressed a much broader scenario than normally required for an exploration well. This information, in Amoco's opinion, should be sufficient to support the application.

Respecting funding, Amoco submitted that dealing with any funding applications at a pre-hearing meeting in January, with time allotted to assess these applications prior to any hearing, would be appropriate.

3 VIEWS OF THE INTERVENERS

The interest groups and local residents represented by Mr. Harvey Locke suggested that the hearing should be held no earlier than May of 1994 in order not to interfere with local calving operations and to allow sufficient time to review the material submitted by Amoco and properly prepare for the hearing.

Mr. Locke submitted that the Maycroft Community Hall would be the most appropriate venue to hold the hearing to allow the attendance and participation of local area residents. Mr. Locke also submitted that it was their intention to file an application for funding for preparation of their submission. He also stated that his clients would want staff from Alberta Environment Protection (AEP) to be available to testify at the hearing, and, if necessary, he would wish the Board to compel their attendance.

Respecting the scope of the hearing, Mr. Locke submitted that the Whaleback Ridge area is environmentally sensitive and ecologically important, both locally and provincially. Given this, the initial question to be addressed at the hearing was whether any new development of the area should occur at all. If development is to occur then the entire potential development must be assessed, not just a single well.

Mr. McCall submitted that to allow time to prepare for the hearing, a date in May was the earliest the hearing should be convened and the venue could be Maycroft. Respecting scope, Mr. McCall stated that the entire potential development should be addressed. Further, the hearing should consider topics such as potential effects on health, traffic, and property values as well as environmental matters.

The Rocky Mountain Ecosystem Coalition (RMEC) supported a May date for the hearing. It also supported Maycroft as a hearing venue but also proposed a parallel process be held in another location, such as Calgary. RMEC also requested that the Board call for the attendance of staff from AEP to address wildlife issues at the hearing. RMEC argued that the scope of the hearing should include the full field development and also address possible cumulative effects of the proposed development.

The Federation of Alberta Naturalists (FAN) supported a May hearing date at the earliest and Maycroft for a hearing location. FAN submitted that the issue of whether development should occur at all must be addressed. If development is to proceed, the scope should include the broad development and an environmental impact assessment. FAN also supported the appearance of provincial employees at the hearing.

The Peigan Nation (the Peigans) supported the May date for the hearing. Although they did not oppose Maycroft as a hearing location, Pincher Creek would be more convenient for them. The Peigans believe the scope of the hearing should be broad in nature and shared the environmental concerns expressed by other interveners. As well, important socio-economic issues should be discussed, including impact on lands the Peigans consider to be traditional lands, sacred sites, and possibly reserve lands.

The Surface Rights Federation supported the position of addressing the development of the entire gas play and not just a single well licence application.

4 VIEWS OF THE BOARD

Considering the remarks of the applicant, the intervening parties and its own schedule, the Board believes that a hearing commencing on 25 April 1994 should allow sufficient time for the interveners to prepare. The corresponding filing date for submissions will be set for 15 April 1994. The Board notes the general support of the participants for the hearing to be held in Maycroft, and accepts that location.

Respecting requests for advance funding, the Board will entertain submissions filed no later than 24 January 1994. If a meeting is required to address these submissions it will be held at the offices of the Board on 27 January 1994, commencing at 9:00 a.m. While not limiting participation the Board expects that only counsel or other persons representing groups or individuals would need to appear at this meeting.

With respect to the scope of the hearing, some guidance is available from IL 93-9, which was issued at the close of the pre-hearing meeting. The contents of the IL had been previously discussed with the applicant, as well as with other companies active in the region.

IL 93-9 deals with potential drilling in the southern portion of the Eastern Slopes. This area has been assessed by the provincial integrated resource planning (IRP) process, which allows for public participation, and by an internal government review process under the Crown Mineral Disposition Review Committee (CMDRC). These processes, both of which include consideration of environmental sensitivities, concluded that the area should not be precluded from potential oil and gas development without site-specific assessment under the provinces' regulatory framework. It is the ERCB's legislated responsibility to provide that site-specific assessment in this case.

The Board normally attempts to determine whether new drilling is in the public interest by comparing the potential value to society of successful development with the potential costs to society imposed by that development. Those costs may include, among other things, effects on local landowners, as well as commercial, social and environmental impacts -- in general, all identifiable adverse effects attributable to the project. There are uncertainties on both sides of the equation, including, for example, the following: the presence of hydrocarbons is never certain until wells have been drilled; the social impact and the impact on the environment may depend on the scale of development and may or may not be mitigable; and the costs associated with development are sometimes difficult to quantify.

The southern portion of the Eastern Slopes is viewed by some members of the public as an important, in some areas untouched, regional ecosystem. Consequently, the Board decided to augment its normal procedures by encouraging companies to adopt a more co-ordinated approach to planning oil and gas development than has been the usual approach. IL 93-9 sets out the Board's expectations for development proposals in the area. The IL is intended to allow sufficient flexibility to accommodate the wide range of existing settings in the region, from relatively intense development to pristine, as yet untouched wildlands.

In areas with no previous energy exploration, the Board recognizes the inherent difficulty in projecting full field development at the stage of planning the first well or even initial delineating wells. The first exploratory well may be unsuccessful, thus refocusing or possibly terminating activity in that region. Or the first well may be extremely promising, suggesting that a detailed, extensive development plan is reasonable and desirable. Or it might be an unfortunate in-between situation, requiring subsequent

judgement with respect to the next well. So the Board has chosen to encourage a sequential approach to delineating and planning development, as described in the IL, that is intended to ensure the planning effort and information requirements are appropriate for the circumstances.

In the case at hand, the proposed site "is on Crown land in an area of improved pasture used by the leaseholder as a spring and fall holding area for cattle" (Application, Tab 1, page 1). At the same time, the valley where the well is proposed may be an important component of the regional ecosystem. The Board would want to be sure that the well would not alter that ecosystem adversely and irretrievably. The question bearing on the scope of the hearing is what nature and scale of information is necessary for such decisions to be reliably made.

Board staff felt, because of the area's potential sensitivity, some aspects of the decision might require more information than is usually provided in an application for a single well. Amoco's response identified three scenarios and went into some detail regarding the assumed development and environmental implications of those scenarios. The scenarios were based on a number of assumptions, some of which would be tested by the drilling of the first well. There is a considerable degree of uncertainty about the potential nature and direction of development at this time.

The application exemplifies a situation contemplated by the Board when it developed IL 93-9: one where some interveners request the broadest possible hearing to make a wide-ranging case against development, while the applicant requests a hearing limited to consideration of one well, the applied-for exploratory well, on grounds that everything else is speculative and would provide little basis for decision at a hearing. In the case at hand, the Board believes the uncertainty associated with early exploration means that attempting to define the complete development, as well as its associated environmental impact, would be, at best, speculative and inefficient and, at worst, simply not possible.

The Board believes it understands the concerns prompting some interveners to suggest this should be a hearing to determine whether any new development is acceptable. Nevertheless, the form of that question the Board must contend with at this hearing is whether or not this specific well and associated infrastructure would cause adverse effects sufficient to justify not allowing it to go ahead.

Therefore, the Board has decided that the hearing should focus largely on the applied-for well and its effects. The Board will be asking interveners to address concerns about the impacts of this well, and to assist it in determining whether or not the potential adverse effects of this well are grounds to deny it — in Mr. Locke's words, whether "the first cut" is really too deep. Some leeway will be allowed for the interveners to address broader issues within reasonable limits. However, the Board notes any future applications would be subject to the Board's scrutiny, as well as that of the interveners, and could give rise to future public proceedings. The Board sees little merit in discussing concerns related to future development that may not occur and, in any case, would be subject to the full review process.

If the first well is approved and turns out to be unsuccessful, that may end the process. Should this well be approved, drilled, and successful in locating hydrocarbons, subsequent applications would require an appropriately greater emphasis on potential environmental impacts, and detailed planning. The application review process associated with each subsequent step will provide further opportunity for interested parties to participate. The Board is confident that this procedure will effectively guard against the possibility of — again using Mr. Locke's expressive language -- "death by a thousand cuts".

Although the Board is conveying by this decision its interest in focusing on the specific application, participants should recognize that the Board does not intend to limit the scope to the very narrow issues relating only to drilling of the well. The applicant will also be asked to address possible production options. For example, if the well were approved and successfully drilled, but further drilling was later denied, the well might have to be produced on its own. With that possibility in mind, the applicant should be prepared to address the impacts of whatever facilities would be needed. The Board notes that this process puts Amoco at risk in ensuring there is sufficient information before the Board to enable it to make a decision. Amoco is also at risk to the extent that investment made in the early stages of drilling may generate a limited return if later environmental or other issues cause the Board to decide full development is not acceptable. Should this well be approved and drilled, the applicant would be well advised to plan to identify the full development requirements as early as possible.

The Board notes the requests to have representatives of Alberta Environmental Protection appear at the hearing and will advise the department of these requests. However, it is not clear to the Board that the potential contribution of those representatives to the decision the Board must make justifies requiring witnesses to appear, should they not wish to do so voluntarily.

DATED at Calgary, Alberta on 31 December 1993.

ENERGY RESOURCES CONSERVATION BOARD

J.P. Prince

J. P. Prince, Ph.D.
Vice Chairman

* R. G. Evans, P.Eng.
Board Member

* N. G. Berndtsson, P.Eng.
Board Member

* Messrs. Evans and Berndtsson were unavailable for signature of this memorandum but concur with its contents.

THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Principals and Representatives (Abbreviations Used in Report)	Representatives
Amoco Canada Petroleum Company Ltd.	F. R. Foran D. G. Arnason
Federation of Alberta Naturalists	Maryhelen Posey
Hunter Creek Coalition	H. Locke
The Whaleback Coalition	H. Locke
Miler and Diane McCall	M. McCall
Rocky Mountain Ecosystem Coalition	M. Sawyer
Piegan Nation	L. Mandell
Surface Rights Federation	H. Gardener
Energy Resources Conservation Board	M. J. Bruni R. Creasey, P. Biol. N. F. Lord

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

AMOCO CANADA PETROLEUM COMPANY LTD. WHALEBACK RIDGE AREA ADVANCE LOCAL INTERVENER FUNDING

Memorandum of Decision
Application No. 931598

1 INTRODUCTION

On 27 January 1994, a division of the Board, comprised of J. P. Prince, B. F. Bietz, and R. G. Evans, considered at a meeting in Calgary, Alberta, submissions received from the Whaleback Coalition, the Hunter Creek Coalition, and the Peigan Nation for advance funding to participate in the upcoming hearing of an application by Amoco Canada Petroleum Company Ltd. for an exploratory well in the Whaleback Ridge Area.

The Board normally considers requests for advance funding through written submissions only. However, in this case a meeting was suggested by the applicant as a way to expedite the process.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) F. R. Foran D. G. Arnason	
Whaleback Coalition G. T. H. Locke	J. A. Tweedie
Hunter Creek Coalition S. J. Ross	E. M. Smith
Energy Resources Conservation Board M. J. Bruni J. A. Dawson J. R. Creasey, P.Biol.	

2 ISSUES

The Board believes that the issues for consideration are

(a) whether the Whaleback Coalition, the Hunter Creek Coalition, and the Peigan Nation are local interveners for the purposes of costs, and

(b) if any or all of them qualify as local interveners, the amount of the advance of funds.

3 ELIGIBILITY FOR LOCAL INTERVENERS' COSTS

To make an advance of costs pursuant to section 31(6) of the *Energy Resources Conservation Act* (the Act), the Board must first determine that the claimant meets the test of "local intervener" as set out in section 31(1) of the Act. The Board must also be satisfied that there is a need for the advance, the proposed budget is reasonable and that the issues to be put forth in the intervention are not outside of the scope of the hearing. In this case, the scope of the hearing is outlined in the Board's Memorandum of Decision on Application No. 931598, dated 31 December 1993, and issued as a result of a Pre-Hearing Meeting held on 14 December 1993 (copy attached).

4 THE WHALEBACK COALITION

The Whaleback Coalition is comprised of Mr. James Tweedie, Mr. and Mrs. Kevin and Gail van Tighem, Mr. Michael Gerrand, the Alberta Wilderness Association, Ms. Dianne Pachal and the Canadian Parks and Wilderness Society.

4.1 Views of the Whaleback Coalition

Mr. Locke submitted that Mr. Tweedie, a member of the Whaleback Coalition, is undoubtedly a local intervener pursuant to section 31(1) of the Act. Mr. Tweedie resides on a parcel of land that is located within the Emergency Planning Zone (the EPZ) submitted by Amoco in their application. He has also registered a caveat on the title of this land in respect of an agreement for the sale of the land.

Mr. Locke stated that Mr. Tweedie's use and enjoyment of this land will be adversely affected by the drilling of the proposed exploratory well in part due to the disturbance of area wildlife. He submitted that there is some potential for being evacuated should an emergency occur at the proposed well and this would also have an adverse affect on Mr. Tweedie and his land.

Mr. Tweedie is a member of the Alberta Wilderness Association (the AWA) and has asked both the AWA and the Canadian Parks and Wilderness Society (CPAWS) to assist him in preparing for the hearing. Amoco and the Board were advised at the meeting that while Mr. Tweedie had requested support from these associations, any costs incurred by members of those associations would not be part of an intervener cost claim. Mr. Tweedie has also asked the other members of the Whaleback Coalition for their assistance.

The Whaleback Coalition submitted that it requires expert assistance in reviewing the following issues:

- wildlife habitat and potential disruption of wildlife populations,

- loss of extensive ecological and recreation values, and
- protection of landscape values,

all in the context of the applied for exploratory well. The desired slate of technical assistance includes an expert in assessing the ecology and landscape values of the Whaleback, an expert in Environmentally Significant Areas studies, a researcher familiar with large carnivore behaviour, a professor of environmental design, and a professor of archaeology. As well, the Whaleback Coalition would retain legal counsel to assist in the preparation and organization of their intervention. It was submitted by the Whaleback Coalition that these issues fall within the scope of the upcoming hearing as outlined in the Board's Memorandum of Decision dated 31 December 1993.

Mr. Locke submitted that no one within the Whaleback Coalition has the funds necessary to allow their full participation in the hearing process. Therefore, there is a need for the requested advance of funds. Mr. Locke suggested that the Board may wish to consider funding the identified experts directly to ensure that the Board has the appropriate information available for consideration during the hearing process.

4.2 Views of Amoco

Amoco stated that Mr. Tweedie is potentially the only member of the Whaleback Coalition that would qualify as a local intervener pursuant to section 31(1) of the Act. Amoco acknowledged that Mr. Tweedie resides on a parcel of land situated approximately 8 kilometres (8 km) south of the proposed wellsite, but within the extended EPZ. While Amoco accepted that Mr. Tweedie qualifies as a local intervener, they did not believe that the other members of the Whaleback Coalition qualify for local intervener status nor should they be eligible for funding based on the qualification of Mr. Tweedie. Amoco also noted that Mr. Tweedie and Ms. Judy Huntley have registered a joint caveat on title in respect of an agreement for the sale of the land and that the registered owner is Edward M. Smith, a member of the Hunter Creek Coalition (see section 5). Amoco believed Ms. Huntley to be a member of the Hunter Creek Coalition and questioned whether, in an attempt to minimize local interveners' costs, Mr. Tweedie should not also be a member of the Hunter Creek Coalition.

Amoco argued that the requested experts, and the involvement of the AWA and CPAWS, indicated that the Whaleback Coalition would be looking at broad regional issues rather than at issues which related directly to an adverse impact to Mr. Tweedie's land. Thus Amoco was opposed to funding of the Whaleback Coalition as the issues it wished to pursue were irrelevant to the scope of the hearing.

If the Board was to find Mr. Tweedie to be a local intervener for the purposes of costs, Amoco indicated it would not object to some advance funding, but only for issues which were relevant to the specific wellsite application before the Board.

4.3 Views of the Board

Based on the information provided by the Whaleback Coalition, the Board is not prepared, at this time, to recognize the Whaleback Coalition as a local intervener for costs purposes. Of the Whaleback Coalition members, only Mr. Tweedie resides sufficiently close to the proposed wellsite to be potentially considered a local intervener, as set out in section 31(1) of the Act. There is, however, a considerable distance between Mr. Tweedie's residence and the proposed wellsite (8 km). The Board did not find the arguments describing potential impacts sufficient to allow it to determine, in advance of the hearing, that Mr. Tweedie's circumstances qualify him under section 31(1). Specifically, the Board does not accept the fact that Mr. Tweedie's land is within the EPZ as reason, in and of itself, to designate him as a local intervener for costs purposes. The Board will consider the matter in light of representations and evidence presented at the hearing.

Because the Board is unable to find that the Whaleback Coalition is a local intervener, no advance of funds can be made. Should the Whaleback Coalition eventually be determined to be a local intervener for costs purposes, it remains responsible for ensuring that any issues for which it would expect to be reimbursed are within the sope of the hearing and addressed in a reasonably expeditious fashion. In particular, should the Coalition argue, and the Board accept, that Mr. Tweedie qualifies because of potential adverse effects related to a possible emergency, eligible costs would be those relating to these possible effects. Broad or general issues which do not address the potential impact of the well on Mr. Tweedie's land are unlikely to be funded.

5 HUNTER CREEK COALITION

The Hunter Creek Coalition is comprised of Mr. & Mrs. Ted and Heather Smith, Mr. and Mrs. Einar and Judy Nelson, Mr. and Mrs. Ronald and Patsy Nelson, Mr. and Mrs. Miles and Diane McKall, Mr. and Mrs. Juris and Margo Krisjansons, and Mr. Tom Moulson.

5.1 Views of the Hunter Creek Coalition

Mr. Ross submitted that the members of the Hunter Creek Coalition were local interveners pursuant to section 31(1) of the Act by virtue of the fact that these individuals have an interest in land in the vicinity of the wellsite and also adjacent lands within the EPZ. Mr. Ross stated that several members of the Hunter Creek Coalition also hold Crown grazing leases near the proposed wellsite. These grazing leases give the Hunter Creek Coalition members local intervener status because they have an interest in land and possess the right to occupy land that may be adversely and directly affected by a decision of the Board.

The Hunter Creek Coalition wished to provide evidence on the same areas as the five experts outlined in the request for advance funding by the Whaleback Coalition. However, they made this request for funding only if funding was not granted to the Whaleback Coalition. In addition to the subject areas to be shared between the two groups (See 4.1), expertise in the following areas was requested by the Hunter Creek Group:

- an oil and gas consultant to provide advice and assistance with respect to the impact exploratory drilling may have on the area;
- an expert on environmental impact assessments to assess the adequacy of the information provided by the applicant;
- a land economist to address cost/benefit issues and to look at alternative uses for the area;
- an expert in the area of human and animal health related to H_2S and SO_2 exposure;
- an hydrologist to review the potential effect the well may have on the groundwater regime;

- a dispersion meteorologist to advise on the impact of emissions; and
- a rancher-historian to gather evidence on the uniqueness of the area and the traditional ranching lifestyle.

The members of the Hunter Creek Coalition do not possess the funds required to retain the experts that they believe are necessary to allow them to fully participate in the upcoming hearing. The advance of funding for the Hunter Creek Coalition was proposed to be held in trust to enable the intervener to engage their required experts. The amount requested did not include legal fees which, the Board was advised, are not being sought in the advance request.

5.2 Views of Amoco

Amoco believed that the Hunter Creek Coalition should qualify as local interveners for funding purposes; however, it expressed a concern regarding the types of experts the Hunter Creek Coalition were proposing and the issues being investigated. Amoco was opposed to the funding of experts addressing broad and general issues, but accepted the request for funding related to the specifics of the application. Amoco also appreciated that the requested funds, if granted, would be held in trust and believed that the amount requested was reasonable.

5.3 Views of the Board

The Board has determined that the Hunter Creek Coalition is a local intervener as set out in section 31(1) of the Act, and is prepared to advance some funds for the preparation of its submission.

The Hunter Creek Coalition is responsible for ensuring that the issues raised are within the scope of the hearing and related directly to the potential adverse impacts approval of the well might have on its lands. As a caution to the Hunter Creek Coalition, the panel members did have some concern regarding the likely relevance of experts on the adequacy of the environmental impact assessment and on the uniqueness of the area vis à vis the traditional ranching lifestyle. The relevance of all experts engaged by the Hunter Creek Coalition will be assessed on the basis of the evidence presented at the hearing.

6 PEIGAN NATION

6.1 Views of the Peigan Nation

The Peigan Nation was not represented at this meeting. However, a written submission on its request for advance funding was filed with the Board. The Peigan Nation said it does not have any independent sources of funding available to it and that to fully participate before the Board, it needed an advance of funds. The Peigan Nation proposed to provide expert assistance to help the Board understand the impacts of the proposed exploratory well on its interests by seeking the following:

- an oil and gas expert to advise on the reasonably anticipated impacts to the environment;
- A Peigan ethnographer to identify spiritual and historic sites to determine the historical and present uses of the area;

- an expert in Peigan history and archaeological sites;
- biologists to determine the impacts to both plants and animals that may affect the Peigan Nation in this area;
- legal representation; and
- a Peigan co-ordinator to relay instructions among the lawyer, the experts and the Band Members.

6.2 Views of Amoco

Amoco did not oppose the granting of the advance of funds to the Peigan Nation as it believed that the Treaty 7 rights conferred on the Peigan Nation may be sufficient to give it local intervener status.

Amoco was prepared to deal with the advance funding request made by the Peigan Nation outside of the local interveners' costs process.

6.3 Views of the Board

The Board notes the undertaking by Amoco to deal directly with the advance of costs requested by the Peigan Nation.

7 DECISION

The Board has a policy of encouraging interveners to join together whenever possible to present an efficient intervention and to avoid duplication of effort and expense. An example of an efficient method to present evidence would be co-operation among the interveners in sharing information gathered by one particular expert dealing with subject matter of common interest. The Board does not see the need to present two or three experts in the same area, nor would the Board expect the applicant to fund that type of duplication. Any of the parties to the hearing which have been, or may in future be, granted local intervener status should be aware that the Board would take these factors into account when deliberating on the final claim for local interveners' costs.

Even though Amoco has undertaken to provide funding to the Peigan Nation outside of the local interveners' costs process, that intervener too should consider the co-operative approach when determining the need for expert assistance.

The Board's decisions on the requests for advance funding are as follows:

1. The Whaleback Coalition

   The Board is not prepared to grant an advance of costs.

2. The Hunter Creek Coalition

   The Board is prepared to grant an advance of costs in the amount of $10,000.00 to the Hunter Creek Coalition for the preparation and presentation of its intervention.

3. The Peigan Nation

The request for an advance of funds filed by the Peigan Nation will be handled outside the local interveners' costs process as Amoco has agreed to fund the Peigan Nation directly.

DATED at Calgary, Alberta on 3 March 1994.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

R G Evans

R. G. Evans, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR A WELL LICENCE
PORCUPINE HILLS-WHALEBACK RIDGE AREA
AMOCO CANADA PETROLEUM COMPANY LTD.

Memorandum of Decision
Pre-Hearing Meeting
Application No. 931598

1 INTRODUCTION

Amoco Canada Petroleum Company Ltd. (Amoco) has applied to the Energy Resources Conservation Board (the Board) for a well licence for a well proposed to be drilled on a surface location in Lsd 9-18-11-2 W5M. The well would be known as AMOCO HUNTER CREEK 10-18-11-2 and would be for the purpose of obtaining production from the Mississippian System. The well would be located in an area of south-western Alberta known as the Whaleback Ridge.

The Board was aware that a number of individuals and interest groups had concerns about the drilling of a well in this area and were requesting that a public hearing be held to address the application. To ensure all parties had an opportunity to set out their position, the Board convened a pre-hearing meeting to receive submissions respecting issues related to the application. The meeting was held at the offices of the Board on 14 December 1993. The Board members presiding at the meeting were J. P. Prince. Ph.D., R. G. Evans, P.Eng. and N. G. Berndtsson, P.Eng. The following major topics were discussed:

1. the location of the hearing,
2. the timing of the hearing,
3. the scope of the hearing, and
4. funding for local interveners.

The names of the participants who registered at the meeting are shown on the attached list.

2 VIEWS OF THE APPLICANT

Amoco stated it would defer to the wishes of the Board and local area residents respecting the location of the hearing. Amoco submitted that the hearing should commence no later than 28 February 1994.

Amoco submitted that the hearing should focus on the proposed well and not be expanded in scope to speculate on future applications since the results of the proposed well would be of paramount importance in determining what development might be proposed in the future. Amoco believed that it had already addressed a much broader scenario than normally required for an exploration well. This information, in Amoco's opinion, should be sufficient to support the application.

Respecting funding, Amoco submitted that dealing with any funding applications at a pre-hearing meeting in January, with time allotted to assess these applications prior to any hearing, would be appropriate.

3 VIEWS OF THE INTERVENERS

The interest groups and local residents represented by Mr. Harvey Locke suggested that the hearing should be held no earlier than May of 1994 in order not to interfere with local calving operations and to allow sufficient time to review the material submitted by Amoco and properly prepare for the hearing.

Mr. Locke submitted that the Maycroft Community Hall would be the most appropriate venue to hold the hearing to allow the attendance and participation of local area residents. Mr. Locke also submitted that it was their intention to file an application for funding for preparation of their submission. He also stated that his clients would want staff from Alberta Environment Protection (AEP) to be available to testify at the hearing, and, if necessary, he would wish the Board to compel their attendance.

Respecting the scope of the hearing, Mr. Locke submitted that the Whaleback Ridge area is environmentally sensitive and ecologically important, both locally and provincially. Given this, the initial question to be addressed at the hearing was whether any new development of the area should occur at all. If development is to occur then the entire potential development must be assessed, not just a single well.

Mr. McCall submitted that to allow time to prepare for the hearing, a date in May was the earliest the hearing should be convened and the venue could be Maycroft. Respecting scope, Mr. McCall stated that the entire potential development should be addressed. Further, the hearing should consider topics such as potential effects on health, traffic, and property values as well as environmental matters.

The Rocky Mountain Ecosystem Coalition (RMEC) supported a May date for the hearing. It also supported Maycroft as a hearing venue but also proposed a parallel process be held in another location, such as Calgary. RMEC also requested that the Board call for the attendance of staff from AEP to address wildlife issues at the hearing. RMEC argued that the scope of the hearing should include the full field development and also address possible cumulative effects of the proposed development.

The Federation of Alberta Naturalists (FAN) supported a May hearing date at the earliest and Maycroft for a hearing location. FAN submitted that the issue of whether development should occur at all must be addressed. If development is to proceed, the scope should include the broad development and an environmental impact assessment. FAN also supported the appearance of provincial employees at the hearing.

The Peigan Nation (the Peigans) supported the May date for the hearing. Although they did not oppose Maycroft as a hearing location, Pincher Creek would be more convenient for them. The Peigans believe the scope of the hearing should be broad in nature and shared the environmental concerns expressed by other interveners. As well, important socio-economic issues should be discussed, including impact on lands the Peigans consider to be traditional lands, sacred sites, and possibly reserve lands.

The Surface Rights Federation supported the position of addressing the development of the entire gas play and not just a single well licence application.

4 VIEWS OF THE BOARD

Considering the remarks of the applicant, the intervening parties and its own schedule, the Board believes that a hearing commencing on 25 April 1994 should allow sufficient time for the interveners to prepare. The corresponding filing date for submissions will be set for 15 April 1994. The Board notes the general support of the participants for the hearing to be held in Maycroft, and accepts that location.

Respecting requests for advance funding, the Board will entertain submissions filed no later than 24 January 1994. If a meeting is required to address these submissions it will be held at the offices of the Board on 27 January 1994, commencing at 9:00 a.m. While not limiting participation the Board expects that only counsel or other persons representing groups or individuals would need to appear at this meeting.

With respect to the scope of the hearing, some guidance is available from IL 93-9, which was issued at the close of the pre-hearing meeting. The contents of the IL had been previously discussed with the applicant, as well as with other companies active in the region.

IL 93-9 deals with potential drilling in the southern portion of the Eastern Slopes. This area has been assessed by the provincial integrated resource planning (IRP) process, which allows for public participation, and by an internal government review process under the Crown Mineral Disposition Review Committee (CMDRC). These processes, both of which include consideration of environmental sensitivities, concluded that the area should not be precluded from potential oil and gas development without site-specific assessment under the provinces' regulatory framework. It is the ERCB's legislated responsibility to provide that site-specific assessment in this case.

The Board normally attempts to determine whether new drilling is in the public interest by comparing the potential value to society of successful development with the potential costs to society imposed by that development. Those costs may include, among other things, effects on local landowners, as well as commercial, social and environmental impacts -- in general, all identifiable adverse effects attributable to the project. There are uncertainties on both sides of the equation, including, for example, the following: the presence of hydrocarbons is never certain until wells have been drilled; the social impact and the impact on the environment may depend on the scale of development and may or may not be mitigable; and the costs associated with development are sometimes difficult to quantify.

The southern portion of the Eastern Slopes is viewed by some members of the public as an important, in some areas untouched, regional ecosystem. Consequently, the Board decided to augment its normal procedures by encouraging companies to adopt a more co-ordinated approach to planning oil and gas development than has been the usual approach. IL 93-9 sets out the Board's expectations for development proposals in the area. The IL is intended to allow sufficient flexibility to accommodate the wide range of existing settings in the region, from relatively intense development to pristine, as yet untouched wildlands.

In areas with no previous energy exploration, the Board recognizes the inherent difficulty in projecting full field development at the stage of planning the first well or even initial delineating wells. The first exploratory well may be unsuccessful, thus refocusing or possibly terminating activity in that region. Or the first well may be extremely promising, suggesting that a detailed, extensive development plan is reasonable and desirable. Or it might be an unfortunate in-between situation, requiring subsequent

judgement with respect to the next well. So the Board has chosen to encourage a sequential approach to delineating and planning development, as described in the IL, that is intended to ensure the planning effort and information requirements are appropriate for the circumstances.

In the case at hand, the proposed site "is on Crown land in an area of improved pasture used by the leaseholder as a spring and fall holding area for cattle" (Application, Tab 1, page 1). At the same time, the valley where the well is proposed may be an important component of the regional ecosystem. The Board would want to be sure that the well would not alter that ecosystem adversely and irretrievably. The question bearing on the scope of the hearing is what nature and scale of information is necessary for such decisions to be reliably made.

Board staff felt, because of the area's potential sensitivity, some aspects of the decision might require more information than is usually provided in an application for a single well. Amoco's response identified three scenarios and went into some detail regarding the assumed development and environmental implications of those scenarios. The scenarios were based on a number of assumptions, some of which would be tested by the drilling of the first well. There is a considerable degree of uncertainty about the potential nature and direction of development at this time.

The application exemplifies a situation contemplated by the Board when it developed IL 93-9: one where some interveners request the broadest possible hearing to make a wide-ranging case against development, while the applicant requests a hearing limited to consideration of one well, the applied-for exploratory well, on grounds that everything else is speculative and would provide little basis for decision at a hearing. In the case at hand, the Board believes the uncertainty associated with early exploration means that attempting to define the complete development, as well as its associated environmental impact, would be, at best, speculative and inefficient and, at worst, simply not possible.

The Board believes it understands the concerns prompting some interveners to suggest this should be a hearing to determine whether any new development is acceptable. Nevertheless, the form of that question the Board must contend with at this hearing is whether or not this specific well and associated infrastructure would cause adverse effects sufficient to justify not allowing it to go ahead.

Therefore, the Board has decided that the hearing should focus largely on the applied-for well and its effects. The Board will be asking interveners to address concerns about the impacts of this well, and to assist it in determining whether or not the potential adverse effects of this well are grounds to deny it — in Mr. Locke's words, whether "the first cut" is really too deep. Some leeway will be allowed for the interveners to address broader issues within reasonable limits. However, the Board notes any future applications would be subject to the Board's scrutiny, as well as that of the interveners, and could give rise to future public proceedings. The Board sees little merit in discussing concerns related to future development that may not occur and, in any case, would be subject to the full review process.

If the first well is approved and turns out to be unsuccessful, that may end the process. Should this well be approved, drilled, and successful in locating hydrocarbons, subsequent applications would require an appropriately greater emphasis on potential environmental impacts, and detailed planning. The application review process associated with each subsequent step will provide further opportunity for interested parties to participate. The Board is confident that this procedure will effectively guard against the possibility of — again using Mr. Locke's expressive language -- "death by a thousand cuts".

Although the Board is conveying by this decision its interest in focusing on the specific application, participants should recognize that the Board does not intend to limit the scope to the very narrow issues relating only to drilling of the well. The applicant will also be asked to address possible production options. For example, if the well were approved and successfully drilled, but further drilling was later denied, the well might have to be produced on its own. With that possibility in mind, the applicant should be prepared to address the impacts of whatever facilities would be needed. The Board notes that this process puts Amoco at risk in ensuring there is sufficient information before the Board to enable it to make a decision. Amoco is also at risk to the extent that investment made in the early stages of drilling may generate a limited return if later environmental or other issues cause the Board to decide full development is not acceptable. Should this well be approved and drilled, the applicant would be well advised to plan to identify the full development requirements as early as possible.

The Board notes the requests to have representatives of Alberta Environmental Protection appear at the hearing and will advise the department of these requests. However, it is not clear to the Board that the potential contribution of those representatives to the decision the Board must make justifies requiring witnesses to appear, should they not wish to do so voluntarily.

DATED at Calgary, Alberta on 31 December 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

* R. G. Evans, P.Eng.
Board Member

* N. G. Berndtsson, P.Eng.
Board Member

* Messrs. Evans and Berndtsson were unavailable for signature of this memorandum but concur with its contents.

THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Principals and Representatives (Abbreviations Used in Report)	Representatives
Amoco Canada Petroleum Company Ltd.	F. R. Foran D. G. Arnason
Federation of Alberta Naturalists	Maryhelen Posey
Hunter Creek Coalition	H. Locke
The Whaleback Coalition	H. Locke
Miler and Diane McCall	M. McCall
Rocky Mountain Ecosystem Coalition	M. Sawyer
Piegan Nation	L. Mandell
Surface Rights Federation	H. Gardener
Energy Resources Conservation Board	M. J. Bruni R. Creasey, P. Biol. N. F. Lord

RECEIVED
[illegible] 1993
[illegible] LIBRARY
[illegible]

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR A WELL LICENCE
RICINUS FIELD
MOBIL OIL CANADA, LTD.

Decision D 94-1
Application No. 931052

1 INTRODUCTION

1.1 Application

Mobil Oil Canada, Ltd. (Mobil) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the Regulations), for a well licence for a well proposed to be drilled from a surface location in Legal Subdivision 10, of Section 35, Township 32, Range 7, West of the 5th Meridian to a projected bottom-hole location in Legal Subdivision 11, of Section 35, Township 32, Range 7, West of the 5th Meridian as shown on the attached map. The purpose of the proposed well, to be known as MOBIL RICINUS 11-35-32-7 (the well), would be to obtain sour gas production from the Leduc formation. The well would be a Level IV critical well with a reduced emergency planning zone of four kilometres.

1.2 Interventions

Interventions to the application were received by the Energy Resources Conservation Board (the Board) mostly from landowners and concerned persons in the vicinity of the well. The area is known locally as the Bearberry Valley and is located north-west of Sundre, Alberta. Those who appeared to speak to their interventions are identified in the following table. The interveners took issue with a number of matters concerning the proposed well. The concerns centred around the potential impacts that could result from sour gas development in the Bearberry Valley. These concerns included safety and environmental impacts (noise, odours, air quality), effects on land values, setback restrictions, effects on livestock and intrusion into their current lifestyles. They submitted the negative impacts were magnified because the Bearberry Valley was, in their opinion, a unique area, particularly from a climatic perspective.

1.3 Hearing

A public hearing of the application was originally scheduled to commence on 14 September 1993. In response to requests for a re-scheduling of the hearing from local area residents the Board directed the hearing to be re-scheduled, which then commenced on 13 October 1993 at the Bearberry Community Hall in Bearberry, Alberta before a division of the Board comprising of N. G. Berndtsson, P.Eng, and Acting Board members, E. G. Fox, P.Eng., and H. O. Lillo, P.Eng.

Following the hearing the panel, accompanied by Board staff, visited the proposed wellsite on 1 November 1993 for the purpose of visual inspection of the site area.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Mobil Oil Canada, Ltd. (Mobil) D. A. Holgate	M. V. Ac, P.Eng. M. K. Bolton, P.Eng. R. P. Kent, P.Eng. S. E. Robertshaw, P.Eng.
Ted and Grace Kostenuke & Swiss-Way Farms (Mr. Kostenuke) R. F. Kutz	T. Kostenuke D. Jones
Kenneth & Margaret Blocksom, (the Blocksoms) Bill and Gay Flug, W. K. Coffin	K. Blocksom M. Blocksom
Gary Theed (Mr. Theed)	G. Theed
Allison Bakken (Ms. Bakken)	A. Bakken
Robert Kneeshaw (Mr. Kneeshaw)	B. Kneeshaw
Betty MacGillivray	B. MacGillivray
Donald and Marlene Harris (Mr. Harris)	D. Harris
Neil Reynolds	N. Reynolds
Energy Resources Conservation Board M. Craig N. F. Lord P. Oscienny, P.Eng. J. Page	

2 ISSUES

The Board considers the issues respecting the application to be:

- the need for the well,
- the location of the well and uniqueness of Bearberry Valley, and
- the impacts of the well.

3 THE NEED FOR THE WELL

3.1 Views of Mobil

Mobil stated there was a need for the well to establish the presence of possible hydrocarbon reserves and to provide Mobil a fair opportunity to produce such reserves from its petroleum and natural gas lease. The drilling of the well was required to meet contractual obligations of the lease. Mobil submitted that the well would provide valuable geological information important in determining what the potential development scenario for the area could be and what, if any, additional drilling in the Bearberry Valley may occur. Mobil stated that if the well was successful there could be significant benefit to the Province of Alberta through additional reserves, royalties and taxes. Further, the preparation for drilling would create opportunities for local contractors.

3.2 Views of the Interveners

In addition to opposing the drilling of a sour well in the Bearberry Valley, the interveners questioned the need for such a well, particularly with present world sulphur prices being so low.

3.3 Views of the Board

The Board accepts that Mobil holds a valid mineral lease for section 35-32-7 W5M and hence has a desire to establish the presence of reserves. The Board also accepts that drilling the well would provide geological information which would be paramount in determining what, if any, future drilling activity may occur. Given this, the Board accepts that Mobil has a need for the proposed well.

Notwithstanding this acceptance the need for the well must be weighed against possible surface impacts to ensure the proposal is in the public interest and would not adversely affect area residents to the point where the Board would deny the application.

4 LOCATION OF THE WELL AND UNIQUENESS OF THE BEARBERRY VALLEY

4.1 Views of Mobil

Mobil submitted it had originally intended to drill a vertical well, but had shifted the proposed surface location in an easterly direction to move the wellsite off lands owned by Mr. Kostenuke because of his opposition to the drilling of such a well on his property. Mobil argued that the alternative surface location, outside the Bearberry Valley as proposed by area residents, was not feasible due to a number of factors. Mobil indicated that directional drilling of the well from a surface location outside the valley would be taking current drilling technology to the outer limits of what is presently feasible. This would also greatly increase the geologic and safety risks associated with such a move. Besides putting the venture beyond economic consideration, Mobil was doubtful if materials in terms of drilling equipment and a rig itself would be available.

Mobil did not believe the Bearberry Valley is significantly different from many valleys in the foothills of Alberta. Mobil submitted it had discussions with Environment Canada and could find no information to suggest the area was more prone to inversions than other areas of the foothills. Further

Mobil had also received weather records from a number of locations in the region which indicated there was nothing unusual about temperature inversion in the Bearberry Valley as compared to other areas.

4.2 Views of the Interveners

The interveners submitted that if drilling for sour gas was to occur in the area at all it should be done from sites outside of the Bearberry Valley. The interveners suggested an alternative location on Crown land located approximately 5 kilometres to the south-west. They contended that this location would eliminate most of the impacts on the residents in the valley although the complete development proposal would still be required to be assessed as to what possible impacts would result.

The interveners submitted that the Bearberry Valley was unique from a micro-climatic perspective, and was particularly susceptible to inversion conditions. This particular characteristic could greatly increase the potential for adverse effects from the presence of a sour well in the valley.

4.3 Views of the Board

The Board accepts that the alternative location proposed by the interveners is not practical and essentially not feasible given today's drilling technology. In this particular case the Board believes that an attempt to drill from the interveners' proposed location would be stretching technological limits and could increase risk and safety considerations for a sour gas well of this nature to a point were the Board would not approve the application

The Board notes that Mobil did not submit any substantive data to refute the interveners submission as to the uniqueness of the Bearberry Valley. The Board recognizes that many areas throughout the Province of Alberta exhibit unique climatic and environmental characteristics. When viewed from a micro-climatic perspective the Board accepts that the Bearberry Valley may have some of the environmental characteristics noted by the interveners. Given this the Board must determine if the potential adverse impacts can be mitigated or reduced to an acceptable level.

5 IMPACT OF THE WELL

5.1 Views of Mobil

Mobil stated that reducing environmental impacts and ensuring safety were important criteria in the design of the operation. This was reflected by Mobil's drilling plan, emergency response plan, and public consultation process. During the drilling phase, state-of-the-art rig equipment would be utilized to reduce noise impact to a minimum. Traffic from heavy equipment and crew changes at the rig would be scheduled to avoid undue traffic impacts and avoid school bus hours.

The lease area would be dyked to ensure no contamination would enter Smith Creek. Non-toxic water based drilling fluids would be utilized and the well would be cased below groundwater aquifers to reduce possible impacts on potable water supplies. A water well would be drilled on the lease site rather than withdrawing water directly from Smith Creek. Respecting the integrity of a sump on the lease, Mobil submitted that results from preliminary test holes indicated that the clay content of the soil in the area was suitable to contain drilling waste fluids. Further the sump fluids would be tested to ensure environmental acceptability.

Mobil recognized the concerns of area residents respecting atmospheric emissions and submitted that with the exception of testing operations no emissions should occur with any of the proposed operations. All possible precautions would be utilized during drilling to ensure no emissions and if the well was productive the facilities would operate as a closed system. Any produced fluids would be pipelined to a gas processing facility outside Bearberry Valley. Mobil was committed to a short testing and flaring scenario operation and anticipated the required information could be obtained with approximately two days of testing.

In the unlikely event a release of sour gas occurred during any operations Mobil had prepared a detailed Emergency Response Plan (ERP) to handle such a situation and ensure the safety of area residents. The plan was developed with all relevant authorities and with information gained from local residents. The plan contained provisions for evacuation of area residents and ignition of the well if safety dictated such measures.

Mobil believed that it had conducted an extensive public consultation process in order to inform and receive the appropriate input from area residents.

Respecting the area residents requests for an overall development plan, Mobil believed that until more geological and reservoir data was acquired these scenarios were highly speculative. In conjunction with the overall development plan Mobil did not believe a detailed environmental assessment was required as sufficient measures where being taken to ensure no adverse environmental impacts occurred.

Mobil did not agree that the Board should defer its decision on the application until the release of the Alberta Cattle Commission study as it was not clear at this time what information would be contained in the report or if it would impact a decision of the Board.

5.2 Views of the Interveners

The interveners stated that they were opposed to the drilling of a sour well and other associated developments. They were familiar with the oil and gas activities already in and around Bearberry Valley and as such were not opposed to these activities, however, Mobil's proposal was for the first sour well in the area.

They submitted that it was not appropriate for the Board to consider only the single well application. Mobil should be required to submit a complete development plan for the valley and all impacts on the residents should be evaluated. In addition an environmental assessment should be conducted on the Bearberry Valley to provide a baseline for environmental analysis.

As well as these broad concerns, the well posed a number of specific concerns which the interveners did not believe Mobil had adequately addressed. These concerns encompassed all phases of Mobil's proposed activities.

Due to the sour nature of the gas expected to be encountered, emissions from both a short-term and long-term effect perspective were of utmost concern. As the valley was characterised by inversions any release could remain in the valley for a substantial period of time before dissipating. As well as the human health considerations, Mr. Kostenuke and Mr. Harris were particularly concerned with the possible impacts to their cattle operations. These livestock operations use embryo transplant techniques which the interveners believe could be sensitive to stresses caused by sour gas emissions.

Mr. Kostenuke contended evidence was available to indicate the adverse impact H_2S emissions could have on livestock production. To this end it was submitted that it would be appropriate for the Board to defer any decision until the information contained in the Alberta Cattle Commission study into the effects of H_2S on livestock could be assessed. Mr. Harris had additional concerns as to the effects emissions would have on his bee and honey production operation as he submitted that bees were very sensitive to emissions of H_2S.

Betty MacGillivray and Mr. Kneeshaw had particular concerns respecting possible emissions and adverse effects on their health. Mr. Kneeshaw submitted he is extremely sensitive to any deviation in air quality. Given this, the proposed well could have a very detrimental effect on his health and lifestyle.

The interveners submitted that many of the specific concerns had not as yet been appropriately addressed by Mobil. Mr. Theed raised concerns of noise as he was the closest resident to the proposed wellsite. Further, Mr. Theed does not have a sense of smell and therefore could not detect fugitive odours. Mr. Theed emphatically stated that should the well go ahead he would not be living on his newly acquired land during drilling operations. Ms. Bakken submitted that possible contamination of the local aquifer and Smith Creek had not been adequately addressed and stated that any sump constructed for drilling operations should be lined.

The Blocksoms submitted that traffic, noise, emissions, health, air and water pollution and safety were all concerns they shared as area residents.

The interveners also submitted that communication had not been sufficient to fully advise them of the measures which would be included in the drilling plan and ERP to adequately address their concerns. Such questions as to livestock handling in the event of an emergency had not been addressed. Mr. Theed raised wildlife protection concerns in the event of an incident. The interveners also questioned the adverse impact the well and further development would have on their property value and their ability to develop their lands as they saw fit in the future. They also submitted that it would be appropriate for Mobil to provide some form of insurance in the way of a performance bond to ensure no financial loss would be incurred by the residents as a result of Mobil's activities.

5.3 Views of the Board

The Board believes that given the measures set out in Mobil's drilling plan and ERP the well could proceed safely. The Board accepts Mobil's commitments respecting additional measures to be undertaken respecting noise abatement. The Board also accepts Mobil's undertaking to ensure that local groundwater aquifers and the adjacent Smith Creek will not be contaminated. The Board does believe however that the integrity of the sump must be confirmed by its field staff and, if unacceptable, appropriate measures shall be taken. As with any drilling sump in the province, Mobil would also have to demonstrate that the drilling waste is non-toxic prior to disposal. Should any alteration to the drilling program require a change in the proposed mud program, Mobil would have to obtain the Board's approval.

The Board concurs with the interveners in recognizing that the Bearberry Valley may exhibit some micro-climatic characteristics and fugitive emissions could have undesirable impacts on the area. The Board also recognizes that if the well was to prove productive the production scenario would essentially be a closed system that takes the produced fluids out of the Bearberry Valley and flaring would be required only in the event of an emergency or possibly very infrequently during a workover on the well. The Board accepts the procedures outlined within the drilling plan to ensure emissions do not occur. The Board does believe however that additional measures should be in place during any testing of the well. The Board believes that any flaring should be scheduled during acceptable meterological conditions. The Board notes Mobil's commitment for a minimum test duration for the well. The test program along with an application for a flaring permit accompanied by an emergency response program must be submitted to the Board for approval.

The Board finds the ERP for the drilling of the well acceptable. The Board is concerned however that communications leading up to the development of the plan could have alleviated some of the concerns that the residents had. The Board believes that companies must recognize the need for good communication with residents at an early stage of development and it is important that the residents take an active part in such communications.

Respecting the need for an environmental assessment and the submission of a complete development plan by Mobil, the Board believes it has sufficient information at the present time to decide on the application for a single well. The Board also believes that it would be inappropriate to defer its decision pending the issuance of the Alberta Cattle Commission study as it is not known what information will result from the study that could impact the Board's decision.

With respect to the concerns of compensation in the event of an incident, the Board believes Mobil has a responsibility and is liable for its actions and projects it undertakes. The Board directs all parties to ERCB Informational Letter IL 89-20 Compensation in Case of Well Blowout, to assist in addressing this matter should the need arise.

6 DECISION

Having carefully considered all the evidence put before it the Board is satisfied that the well can proceed in a safe manner with minimal impacts to area residents and the surrounding area. In this case the Board is of the opinion that the applicant has a clear obligation to prevent and minimize impacts such as noise, flaring, odours or other such effects. Additionally the requirements of the Board's regulations and if necessary the surveillance by Board staff should ensure adherence to matters within the guidelines of the Board. Given this, the Board is prepared to approve the application subject to the requirements, conditions and regulations of a well of this nature, as well as the following additional detailed requirements:

- the integrity of the sump to contain drilling fluids shall be inspected and approved by the Board's field staff prior to the commencement of operations,

- the drilling waste fluids shall be tested by Mobil to ensure environmental acceptability,

- the testing of the well shall be limited to a pre-approved minimum period required to obtain the necessary information,

- persons within the four kilometre emergency planning zone shall be notified prior to the commencement of testing operations,

- during any testing operations Mobil shall continuously monitor downwind of the lease for the presence of emissions.

Accordingly a well licence will be issued in due course.

DATED at Calgary, Alberta on 13 January 1994.

ENERGY RESOURCES CONSERVATION BOARD

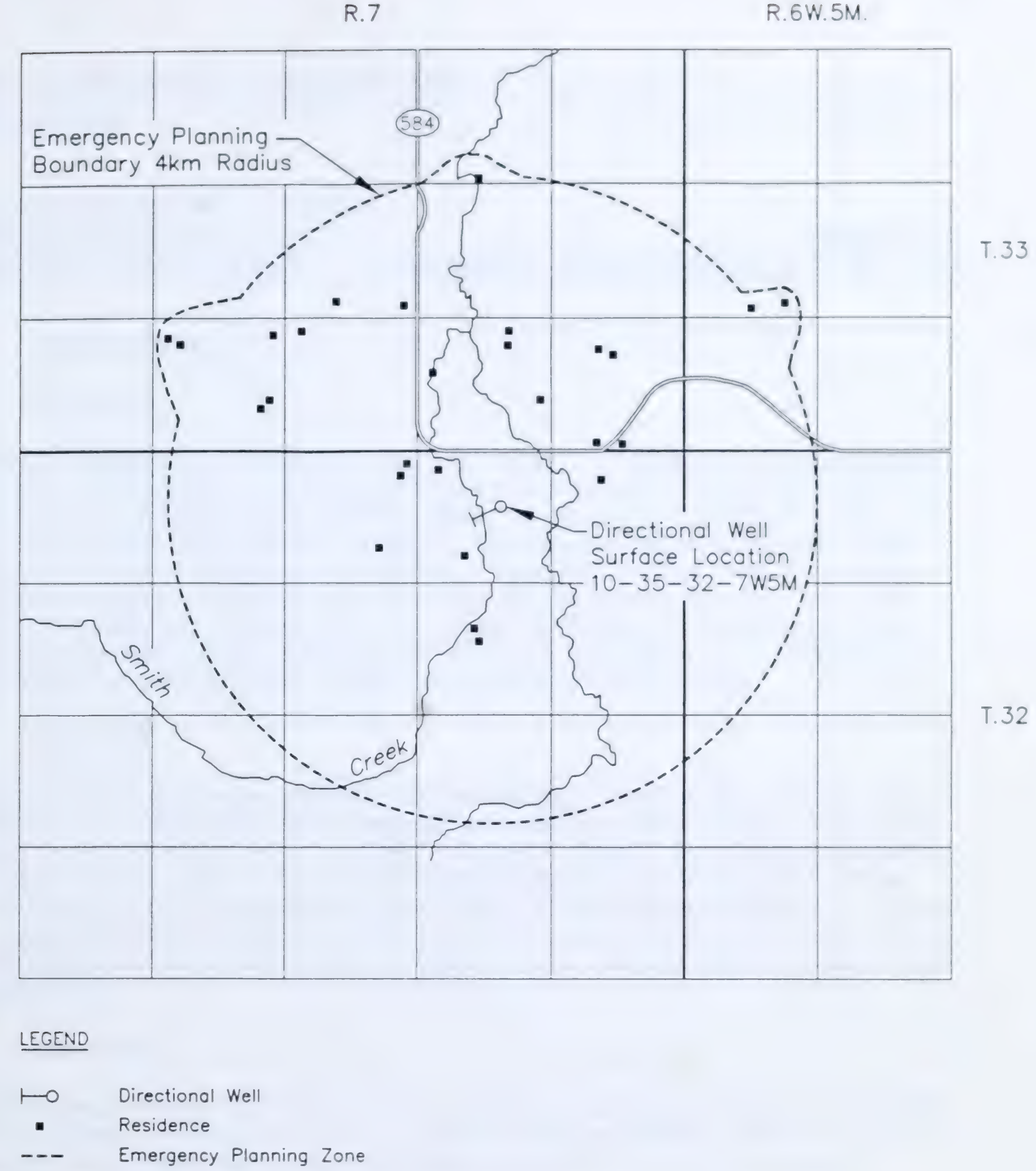
N. G. Berndtsson, P.Eng.
Board Member

E. G. Fox, P.Eng.*
Acting Board Member

H. O. Lillo, P.Eng.
Acting Board Member

---

* E. G. Fox was unavailable for signature of this report but concurs with its contents.



APPLICATION FOR WELL LICENCE
APPLICATION NO. 931052
MOBIL RICINUS 11-35-32-7

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATIONS FOR WELL LICENCES
MOOSE MOUNTAIN AREA
HUSKY OIL OPERATIONS LTD.

Decision D 94-2
Applications No. 931689, 931696, 931746, 931747, 931748

1 INTRODUCTION

1.1 Applications

Husky Oil Operations Ltd. (Husky) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the Regulations) for well licences for five wells proposed to be drilled from three surface locations in Legal Subdivision 13-12-23-7 W5M (Pad 2, two wells), 2-23-23-7 W5M (Pad 1, one well), and 16-22-23-7 W5M (Pad 3, two wells) (Figure 1). The wells would be known as HUSKY RIGEL MOOSE 10-12-23-7, 12-12-23-7, 10-14-23-7, 10-22-23-7, and 2-27-23-7 respectively. The ultimate purpose of the wells would be to obtain production from the Turner Valley Formation. During this phase of the development, however, one well on each pad would be used for delineation and testing of the productivity of the reservoir while the second well on each pad would be used for a closed system testing program in which the produced fluids would be reinjected into the reservoir.

1.2 Background

Husky, as operator, had previously drilled a discovery well at Pad 1 in the winter of 1992/93. The discovery well is located within a 6400 hectare (ha) area located near Moose Mountain in Kananaskis Country for which Husky and its partner, Rigel Oil & Gas Ltd. (Rigel) had acquired the petroleum and gas rights (Figure 2). This well had encountered approximately 70 metres of net pay in the Turner Valley Formation. Due to spring breakup, testing of the well was somewhat inconclusive. The limited test results indicated that the well was capable of up to 800 barrels per day (127 cubic metres per day) of sour light gravity oil. The solution gas, produced with the oil, contained some 33 per cent hydrogen sulphide (H_2S).

1.3 Interventions

Interventions opposing the applications were received by the Energy Resources Conservation Board (the Board) on behalf of several groups (Table 1). The interveners raised a number of concerns relating to the applications, including impacts on the environment, on the use of the area for hunting and recreation, and on public safety.

Rigel appeared at the hearing in support of Husky's applications.

1.4 Pre-Hearing Meeting

A pre-hearing meeting was convened at the offices of the Board in Calgary on 2 December 1993. The purpose of the pre-hearing meeting was to receive submissions as to the need for a public hearing of the applications and the timing and scope of a hearing, should one be required.

Subsequent to the meeting, the Board issued a Memorandum of Decision (attached) dated 9 December 1993. The report directed that the applications be set down for a public hearing, set out the dates for the submission of interventions, and described the requirement of the Board for written submissions.

1.5 Hearing

A public hearing of the applications commenced on 24 January 1994 before a division of the Board consisting of Dr. B. F. Bietz, P.Biol. (Chairman), N. G. Berndtsson, P.Eng., and R. G. Evans, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Husky Oil Operations Ltd. (Husky) F. M. Saville R. Neufeld	M. A. Langley, P.Eng. B. W. Worbets S. D. Butler, P.Eng. V. A. Cuschieri, P.Geol. K. M. Beloglowka, P.Eng. T. Beck P. M. Ullman, P.Eng. R. D. Glaholt, P. Biol.
Rigel Oil & Gas Ltd. (Rigel) K. F. Miller	
Old Sarcee Band, Uterus Clan F. J. Fraser	
Bragg Creek Environmental Coalition C. G. Docken	
Tsuu T'ina Nation H. R. Hansford J.R.W. Rath	L. Crane J. Big Plume
Alberta Justice G. D. Sprague P. Michalyshyn	
Green Peace Climate Change Campaign (Green Peace) K. Jardine	K. Jardine
Western Canada Wilderness Committee W. G. Jones	
The Wildlife Foundation B. L. Horejsi	B. L. Horejsi
Rocky Mountain Ecosystem Coalition M. Sawyer	M. Sawyer D. Mayhood

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Resources Conservation Board staff R. D. Heggie R. Creasey, P.Biol. N. F. Lord	

2 PRELIMINARY MATTERS

2.1 Request for Adjournment

The Tsuu T'ina Nation requested an adjournment of the hearing to allow Husky the opportunity to study the impact of the applications on the Tsuu T'ina Nation's treaty and aboriginal rights as set out in Treaty No. 7 and enshrined in section 35(1) of the Constitution Act, 1982. Counsel for the Tsuu T'ina Nation cited the case of R. v. Sparrow [1990] 1 S.C.R. 1075, as an example of how the rights of the Tsuu T'ina Nation should be considered by the Board.

The Tsuu T'ina Nation suggested that these issues should have been addressed during Husky's public consultation process as set out by the Board's Informational Letter IL 93-9. The Tsuu T'ina Nation also asked that if the Board was unwilling to require that Husky address these issues, an adjournment be allowed in order to provide the Tsuu T'ina Nation the opportunity to prepare its own submission.

Husky argued that it was not obliged to gather evidence or in some other way address rights claimed by one party when no evidence had been presented as to either the nature of those rights or as to how those rights had been infringed. Alberta Justice concurred with Husky's view that there was an onus on the Tsuu T'ina Nation to present a prima facie case with regards to the rights it believed would be affected by Husky's application. Alberta Justice also argued that in cases where rights had not been clearly established, as was the case under Treaty 7 and section 35(1) of the Constitution Act, 1982, it was not appropriate for an administrative tribunal to arbitrate the nature of those rights.

The Board agreed with the view that there was an obligation on the Tsuu T'ina Nation to demonstrate what rights may be affected by a decision of the Board and so was not prepared to require that Husky address the effect of their proposal on the Treaty 7 rights of the Tsuu T'ina Nation. In the Board's view it was not enough for the Board to simply accept that the rights obtained by the Tsuu T'ina Nation through Treaty No. 7 were of a similar nature and extent as those alleged in argument by the Tsuu T'ina Nation. As a result, the Board ruled that it was not prepared to adjourn the hearing in order for Husky to address this issue. The Board also noted at the hearing that it did not believe it was the appropriate authority to determine the nature of those rights.

With respect to the application of IL 93-9 to Husky's application, the Board's view was that IL 93-9 was intended as a general guide for the preparation of submissions. IL 93-9 sets out the general information requirements of the Board for potential new developments in the southern portions of Alberta East Slopes. This includes the type and extent of public consultation and of environmental assessment applicants may be expected to carry out at various stages of development. Unless otherwise directed by the Board, it remains the responsibility of an applicant to determine which, if any, issues it believes relevant to the Board's decision. Should the Board later determine that an issue to which the applicant was non-responsive was of sufficient importance to prevent the approval of an application, this is a risk borne by the applicant.

Finally, with respect to the request that the Board adjourn the hearing to allow the Tsuu T'ina Nation to expand upon its submission, the Board determined that its Rules of Practice had been applied fairly to all parties and that the Tsuu T'ina Nation had a reasonable opportunity to prepare its submission and to participate in the hearing. Therefore, the Board was not prepared to adjourn the hearing.

2.2 Request to Require Attendance of Witnesses

At the pre-hearing meeting of 2 December 1993, the Board was advised by the Rocky Mountain Ecosystem Coalition that it may request that certain witnesses from Alberta Environmental Protection (AEP) appear at the hearing. The witnesses were not identified nor were arguments made as to why it was necessary to compel these witnesses to attend. During the hearing, a similar request was made. It was argued that at least two witnesses from AEP were necessary to speak to decisions that were made by government officials regarding the Mineral Surface Leases (MSL) and Licences of Occupation (LOC) issued by the Crown to Husky for access to public lands. The interveners believed it was necessary to have witnesses from AEP appear before the Board to respond to questions as to why certain decisions were made regarding the location of the access roads and pads, as well as the construction techniques for these facilities.

For the Board to consider compelling the attendance of a witness, it must be convinced that the evidence which would be adduced is critical for the Board to understand the issues it is charged to address. Further, it must be clear that there is no other reasonable way to obtain this evidence. As a result, compelling and substantive reasons are needed for the Board to take such action. In this instance the requested witnesses may be best able to speak to the reasons why certain government decisions were made. However, the interveners failed, in the Board's view, to establish any substantive reasons as to why this information would be critical to the Board's decision or why such evidence could not be brought forward in another fashion.

The Board is of the view that it is the applicant's task to convince the Board that its proposal is in the public interest. Any constraints placed on that proposal by other regulatory agencies simply become components of the project that the proponent must incorporate when it applies to the Board. While permission to proceed with development from AEP is not in any way detrimental to Husky's application, it is also not sufficient to guarantee that the project will also meet the broader tests of the Board.

2.3 Rules of Practice

Questions were raised throughout the hearing concerning the Board's procedures as set out in its Rules of Practice and concerning the presentation of evidence. Of particular concern to the Board in this instance was the practice adopted by the Rocky Mountain Ecosystem Coalition and the Wildlife Foundation of the use of oral rather than written submissions to make complex technical arguments.

The Board believes that, subject to certain limitations, a tribunal has control over its own procedures. This discretion is often difficult to exercise as it demands a balance be struck between competing claims of expeditiousness and fairness. The Board is not, by its enabling legislation, bound by the rules of evidence and its practices and procedures have developed in a way that allows considerable latitude in the type of evidence it will entertain and the fashion by which it may be presented. The Board has done so because it believes this has best served the overall public interest by creating easier access to the administrative process. Associated with that flexibility, however, is a duty for the Board to ensure the process remains fair to all parties, applicant and intervener alike.

The reliance on only oral evidence by an intervener for complex arguments presents the Board, the applicant, and other interested parties with some difficulties. In the Board's view oral presentation of a technical issue raises questions as to how effectively that information may be understood and tested by other interested parties. Moreover, it presents an applicant with the unenviable dilemma of either poorly testing the issues raised or of having to request an adjournment of its own application in order for it to properly assess the new evidence. In this case, the Board notes that the applicant chose not to object to the admission of the oral evidence and the Board accepted the oral interventions into the record.

A second practice which caused concern was the decision of certain interveners to file an intervention but to not provide a witness to speak to the intervention or to answer questions arising from it. The Board normally receives all interventions that are not completely irrelevant into the record. Once on the record, the question of weight is then assessed, including the extent to which that evidence may be relied upon by the Board in its decision. Factors that may tell against weight include a lack of opportunity for cross-examination. The decision by interveners not to provide such witnesses was considered by the Board in determining the appropriate weight to give to various submissions.

In a similar vein, the Board was concerned with the decision by the Wildlife Foundation not to tender as evidence a number of view graphs that were referred to in its oral submissions. Although the Board recognizes that the transcript speaks for itself, the Board was presented with some difficulty in reviewing the transcript insofar as particular view graphs were not entered into the record and were not sufficiently described in the transcript to allow the Board to clarify the evidence of these interveners. To the extent that the view graphs were necessary for the Board to properly understand the evidence, the Board was forced to disregard that portion of the evidence that was not clearly and fully submitted.

3 ISSUES

After careful review of the various concerns raised by the parties at the hearing, the Board believes the main issues to be considered are:

- the need for the wells,
- the testing procedures for the wells,
- public consultation,
- environmental assessment,
- environmental impacts,
- traditional use of Moose Mountain,
- public safety,
- public access, and
- greenhouse gases.

Each issue is addressed separately below.

4 NEED FOR THE WELLS

Husky noted that, in consort with Rigel, it had acquired the petroleum and natural gas rights within the lands in question. While the original discovery well had confirmed the presence of hydrocarbons, Husky had been unable to perform an adequate test of the well's productivity. Even if proper testing had been possible, Husky was of the view that further delineation of the pool was necessary to determine whether commercial development of the reservoir was feasible. Since it was necessary to test along the predicted trend of the reservoir in both directions, wells at both Pads 2 and 3 were required to adequately determine whether further development was warranted. The results at any one pad, Husky stated, would not preclude the need for the other pads.

At the hearing, Husky was questioned regarding the possibility of using only Pad 1, which had already been constructed, to delineate the pool. Husky replied that it was technically possible to drill from Pad 1 to the areas to be covered by Pads 2 and 3 and that this had been considered by Husky because of the potential economic benefits. Ultimately, however, the proposal was rejected in part because of greater expense and in part due to greater risks. The risks included a much lower chance of successfully reaching the target zones for either the northern or southern wells from Pad 1.

The Board notes that while a number of parties argued against the development because of its social, environmental, and public safety aspects, there was no dispute of Husky's right to recover the petroleum and natural gas resources. Nor was the need to further delineate and test the reservoir questioned; only the manner by which that might be accomplished. The Board accepts Husky's right to explore for the oil and gas resources at Moose Mountain and accepts that, provided the development can be carried out in an acceptable fashion, that there is a need for the wells. The Board also accepts that, provided all other issues can be addressed, the proposed drilling program from three separate surface locations is technically feasible and an acceptable approach.

5 TESTING PROCEDURES FOR THE WELL

It was Husky's view that, due to the characteristics of the reservoir, an extended testing period (90 days) would be necessary to determine reservoir flow characteristics and the degree of lateral extent of the reservoir. These data would be critical to determine the design criteria for possible future production facilities.

Husky proposed to use a second well drilled at each pad for reinjection of produced fluids back into the reservoir. This would, it argued, greatly reduce visual impacts from flaring, and the risk of odours, noise, dust, and other forms of disturbance from trucking of fluids. At the hearing, Husky expanded slightly on its original application and confirmed that it proposed to use dual tubing strings to separately reinject the solution gas and the other fluids. Husky also confirmed that this testing approach was relatively untried so it was not completely confident it could be carried out successfully. Should this process not be successful, Husky noted that it would be required to request approval from the Board for some alternative testing procedure.

The Board concurs with Husky's view that the proposed testing methods, while not guaranteed to be successful, do have a significant potential to reduce environmental impacts. This is particularly true in the Moose Mountain region where extensive flaring for long periods and the trucking of sour fluids, particularly during the summer months, could be anticipated to have an impact on recreational users.

The Board believes that reinjection of the produced fluids is technically sound and has an excellent chance of being successful. The Board notes that the use of tubing to produce and to inject sour reservoir fluids is required under the Regulations (section 6.101). In this instance, the Board accepts Husky's proposal for reinjection of solution gas and other liquids. Should reinjection prove not to be feasible, the Board would require Husky to submit an appropriate amendment outlining in detail the reasons for the change in testing procedures, the likely impacts of proposed alternatives, and options for mitigating those impacts.

6 PUBLIC CONSULTATION

Husky noted that it had discussed its development plans with regulatory agencies, environmental interest groups, and local residents near the Moose Mountain project area, as well as with other area oil and gas operators. A large number of special interest groups which use the Moose Mountain area were also consulted during preparation of its Emergency Response Plan.

As a result of these discussions, Husky was of the view that it had been able to address a number of regulatory concerns, particularly those raised by AEP staff. It also had a better understanding of the concerns raised by the various environmental groups. Finally, Husky had established good communications, including an offer to trade seismic data with other operators interested in the region. This latter discussion had been held, in part, in order to reduce unnecessary duplicative disturbance and the associated environmental impacts.

With regard to consultation with area residents, Husky noted that despite distribution of an information circular mailed to residents with a Bragg Creek mailing address on 9 September 1993 and publication of the same circular in the High Country Times, it had, as of 28 September received only one expression of concern by a Bragg Creek resident. Husky confirmed at the hearing that it had also held one meeting with the Tsuu T'ina Nation on 15 November 1993 and had met on several occasions from late December 1993 onward with the Bragg Creek Environmental Coalition. Husky also noted that its project had received a significant amount of coverage by various forms of media.

Husky was of the view that it had conducted an effective and reasonable public consultation program and, while the program had been largely carried out before the issuance of IL 93-9, it had met both the spirit and the intent of that IL.

At the hearing, the Tsuu T'ina Nation was particularly critical of the process used by Husky to advise it of the project and of the potential impacts on its members' use of the area. It noted that the circular was not mailed or in some other way delivered to the residents of the Tsuu T'ina Nation living on the Sarcee Reserve despite its proximity to Bragg Creek. It was also suggested that the meeting of 15 November 1993 was an inadequate attempt at consultation for several reasons. These included a failure to advise the proper people within the band of the project (i.e. the Band Chief and Councillors) and an emphasis at the meeting on economic opportunities rather than on potential impacts. As a result, the Tsuu T'ina Nation contended that Husky did not have an adequate appreciation of the value of the Moose Mountain area to native peoples and had not met either the spirit or intent of IL 93-9.

The Board notes that over the past year, and most recently in IL 93-9, it has advised proponents of energy developments in the Eastern Slopes region of the need for early and open public consultation with interested parties. Such consultation is required in order to identify stakeholders and potential issues and, where possible, to resolve those issues. Depending on the sensitivity of the region proposed for development, operators have been advised that the public consultation process may need to be significantly expanded from that needed in other areas of the province.

The Board believes that, to a large degree, Husky has met its requirements with regard to public consultation. While the Board does not consider the discussions with government regulatory agencies as "public" consultation, other than as an initial tool to identify possible affected stakeholders and their issues, the Board does accept that Husky has made a genuine and appropriate effort to consult with the public and to resolve issues.

The Board does not believe, however, that consultation with the members of the Tsuu T'ina Nation was as effective as it could have been. The Board believes that Husky could have been more proactive in advising the Tsuu T'ina Nation regarding its application. Husky could also have been more sensitive to the unique political structure of native groups, which can make public consultation tools such as mail outs and newspaper articles less effective in their communities. It is not enough to assume, particularly with native groups, that lack of response constitutes a lack of concern.

On the other hand, the Board believes there was also some onus on the Tsuu T'ina Nation to be more proactive in advising Husky of its concerns. Given the significant media coverage of the proposed development, even if 15 November 1993 represented the first formal meeting between Husky and the Tsuu T'ina Nation, the Board finds it difficult to understand why it would take an additional 2 months for the Tsuu T'ina Nation to advise Husky of the extent of its concerns with the proposed development. An applicant can only address issues with the public if it is aware of those issues. Public consultation will only be effective if the public assumes some responsibility for ensuring its concerns are brought to an applicant's attention.

Should approval for this development be granted, the Board will expect Husky to meet its undertaking to establish ongoing consultation with the Tsuu T'ina Nation to ensure that both parties understand the communication needs of the other, as well as to attempt to address any unresolved issues.

7 ENVIRONMENTAL ASSESSMENT

Although IL 93-9 was issued some time after Husky had submitted its application to the Board, Husky suggested that it had a reasonable understanding of the environmental information requirements of IL 93-9 and had in general met the intent of that document. Although it did have a successful discovery well, Husky believed that the new wells still represented the earliest stages in reservoir delineation. This was due in part to the complex geology in the area and also because testing of the discovery well had been abbreviated. Because the information on the eventual size of the pool was so limited, Husky was unable to estimate the possible extent of a commercial development or even whether a commercial development would occur. This in turn significantly reduced its ability to determine the possible environmental impacts of the eventual development. Husky contended that its application for Moose Mountain contained much more environmental data than had historically been required and was adequate for a project in such an early delineation stage.

Husky noted that clearly there were a number of remaining gaps in the environmental data base for the project area. Husky believed, however, that those gaps would be more appropriately filled once it was determined that the project was commercial and a more accurate estimate of the eventual scope of development could be made. The company argued that if the test wells proved unsuccessful, oil and gas activity in the area might be concluded in 9 months, with only reclamation activities remaining, and therefore a more complete environmental assessment was not warranted at this time. Should the test wells prove successful, Husky indicated it was committed to carrying out a complete environmental assessment of any future development. In the interim, Husky believed that it had responded to any environmental data gaps by always taking a conservative design approach whenever actual environmental sensitivity was unknown. Finally, Husky argued that, in acquiring its MSLs and LOCs from AEP, many potential environmental impacts had either been avoided or mitigated to the satisfaction of AEP officials.

Husky's application did not deal specifically with the issue of cumulative effects assessment. In response to questioning during the hearing, Husky indicated that it did not believe that it was fair to require or perhaps even possible for an individual applicant to carry out such an assessment. A primary concern was the inability of an individual company to gain access to the relevant development plans of other companies or industries. Husky suggested that it would be more appropriate for government to carry out a cumulative effects assessment, in cooperation with industry.

A number of interveners challenged the adequacy of the environmental data presented by Husky. They noted, for example, that although Husky conceded that impacts to wildlife would occur, Husky was unable to comment on the regional significance of those impacts. Particular areas of concern included impacts on species with unique habitat requirements and population pressures such as grizzly bears and cutthroat trout. Such species, they argued, were present in the area and particularly sensitive to interactions with humans. Husky, they believed, had failed to address their concerns regarding the long-term viability of these species (see Section 8, Environmental Impacts). Similar concerns were raised with regard to impacts on other users of the area. For example, it was argued that Husky did not have an adequate assessment of the number of non-native recreational users in the region or of the use of the region by natives for hunting and spiritual purposes. Because these data were lacking, it was argued that Husky was unable to accurately assess the impacts of its proposals.

These concerns were exacerbated, the interveners suggested, by Husky's inability to adequately delineate the extent of its future development if the project proved to be commercially successful. Also lacking, they argued, was any description of monitoring programs to assess the impacts of the proposed development (including the success of the proposed mitigation measures) or of the issues which Husky proposed to address in any subsequent environmental assessment. Finally, the interveners noted that Husky had not attempted to describe or assess the cumulative effects of the various industrial, recreational, and agricultural developments in the area. The interveners noted that mitigation measures, monitoring, and cumulative effects were among the environmental issues raised in IL 93-9 and argued that Husky was obliged to address these.

The primary question raised by the interveners, in the Board's view, is whether the environmental information presented by Husky in its application is adequate for the Board to determine whether the new development would be in the public interest.

It was clear from the evidence presented that the area proposed for development by Husky is already used for a number of purposes, including ranching, logging, oil and gas development, hunting, hiking, and several other forms of recreation. A significant amount of public access, via either roads or trails, also exists. Although the development proposed by Husky would clearly be incremental to existing development, it would by no means be unique or inconsistent with other area activities.

Oil and gas development, unlike many other forms of industrial development, is normally a step-wise process, with each new step contingent upon the earlier success (or lack thereof) of the previous step. The application which the Board has before it is for one of the earliest steps in the process. It is, in effect, a two-well delineation program in which activity, including testing, will last for a 9-month period. If successful, Husky will be required to assess the environmental impacts of a commercial development at a level appropriate to the potential magnitude and duration of such a project, a commitment made by Husky at the hearing. Such an assessment would also include monitoring and impact mitigation programs. If unsuccessful, Husky committed to commence reclaiming the disturbed areas as soon as possible, following any requirements of AEP.

The Board concurs with the views of both Husky and some of the interveners that its development will have an as yet unknown impact on local wildlife habitat and populations. Some degree of wildlife disturbance is likely inevitable and this issue is addressed in more detail in Section 8. The Board does accept that Husky has, in this case, provided a reasonable description of existing environmental conditions that is adequate for the Board to assess the environmental affects of Husky's current project on area wildlife and wildlife habitat. The Board does note that the regional environmental data base, including that for wildlife, appears to be quite limited. Should Husky anticipate a permanent commercial development, the Board does believe that a more extensive environmental assessment for the region would be required in order to determine that commercial production would be in the public interest.

With regard to cumulative effects assessments, the Board is of the view that, at this time, the methodology and standards for such studies remains poorly defined. Until these have been adequately addressed, the Board believes that such an assessment would be premature. The Board also notes Husky's concerns with regard to how such an assessment might be carried out and who should be responsible. The Board had included some assessment of cumulative effects in its list of environmental items to be considered in IL 93-9, in part to ensure that the IL was consistent with requirements set out in the Alberta Environmental Protection and Enhancement Act, and in part because the Board recognized potential merit in the concept. However, the Board is also unclear as to how or by whom such assessments should be conducted. These issues require further consideration and clarification before deciding in what fashion applicants for East Slopes energy developments may be required to address cumulative effects.

With regard to obligations on applicants arising from IL 93-9, in the Board's view IL 93-9 was developed in part to ensure that any new development in the southern portions of the East Slopes was carried out in an orderly, efficient, and economic manner, and in part to ensure potential applicants have a better understanding of the minimum standards expected by the Board. With respect to orderly and efficient development, the Board notes that Husky is still at the earliest stages of development. Although the initial discovery well does provide an indication that the area may contain commercial reserves of hydrocarbons, this is by no means certain. As noted earlier, the Board believes the additional wells are a reasonable step in determining whether future development is likely.

Based on the evidence presented, the Board is willing to accept that Husky's application is a reasonable description of the likely environmental impacts of a short-term delineation phase development and is consistent with IL 93-9. While the eventual environmental impacts of a commercial development may be significantly different from those of the applied-for project, those impacts are much more appropriately dealt with at a later step in the process when the nature and extent of the hydrocarbon resource has been better established. The Board believes that Husky's application and the evidence presented in the hearing is sufficient for it to assess whether approval of the proposed development would be in the public interest.

8 ENVIRONMENTAL IMPACTS

In order to delineate the Moose Mountain reservoir, Husky proposed to construct approximately 8 kilometres (km) of new roads and construct two new surface pads approximately 4 ha in area. The final location of both the pads and the roads had been determined in consultation with AEP.

Husky believed that it had taken a proactive approach in its overall surface development. Should the project prove to be commercial, the pads had been located so as to allow a number of wells to be drilled from a single location, thereby greatly reducing the need for pipeline corridors, access roads, and other surface disturbance. Husky felt it had selected pads sites which minimized environmental and aesthetic impacts (particularly if the project should prove to be commercial), while still meeting its needs from a geological and drilling perspective.

The construction of new roads to Pads 2 and 3, when combined with the existing road to Pad 1, would provide a potential new access route, particularly for motorized vehicles, into the region. Husky stated that it had been instructed by AEP to ban public access to the new roads and was prepared, to the best of its ability, to do so. To that end, Husky noted that it had installed a locked gate at the base of its access road. In Husky's view, the gate had been successful in preventing new public access to the area. Husky also noted its access roads had to some extent followed existing trails.

Husky noted that both the existing and the proposed pads were located within Zone 5; that is, areas classified by the Kananaskis Country Sub-Regional Integrated Resource Plan for multiple use. Pad 2 was to be located in an alpine region between Jumping Pound Mountain and Moose Mountain, while Pad 3 was at a lower elevation with coniferous forest vegetation. The Pad 2 site was selected by Husky in order to minimize future environmental impact from pipelines and access roads should the project become commercial. Husky pointed out that it had considered locating Pad 2 further to the south but had rejected this option since it would have required a new road (and possibly pipeline development) from the south along Canyon Creek. While the access road to Pad 2 skirts the boundary between Zone 1 (prime protection) and Zone 5, Husky believed that this location represented an optimal route from the perspective of forest/vegetation damage and aesthetics (visibility).

With respect to the road to Pad 3, Husky noted that it had, to the best of its ability, located the road above the valley floor and to the north of Cox Hill Creek. Husky also noted that flow along the upper sections of Cox Hill Creek was intermittent and Husky rated the environmental sensitivity of the area containing Pad 3 and its access road as low.

The Rocky Mountain Ecosystem Coalition and the Wildlife Foundation argued that the proposed pads and access roads were unacceptable due to their likely impacts on the ecological integrity of the area. They believed that development throughout the East Slopes had reduced or degraded available habitat to the point that many species were now endangered, and this in turn would eventually lead to the degradation of the entire ecosystem. It was argued that the concept of multiple use along the East Slopes, which includes oil and gas development, was essentially incompatible with managing the land in order to maintain or enhance the abundance, diversity, and distribution of the fish and wildlife resources. They suggested that development in this region had reached the point that, irrespective of the Husky development, the ecological integrity of the East Slopes was in significant danger.

It was argued that public values had shifted in recent years, with a much greater concern now being expressed by the public regarding the protection of habitat and of wildlife. The interveners noted that although legislation such as the Endangered Species Act found in the United States did not exist in Canada, in their view such legislation would be strongly supported by the Canadian public. In the intervener's view, the recent changes to section 2 of the Energy Resources Conservation Act (the Act) increased the responsibility of the Board to incorporate these issues into its decisions. They argued that if the Board decided to deny this application, this would be a critical first step in ensuring that government agencies responsible for land use planning began to address the intervener's concerns around the full scope of human impacts on the area's environment.

Specific concerns were raised with the potential impacts of road construction on grizzly bears and on fish habitat. The Wildlife Foundation argued that the presence of new roads, even at very low densities, have a tremendous impact on many species of wildlife, but particularly on bears. It was noted that in one study, 63 per cent of the recorded bear kills occurred within 1 km from roads. These deaths were the result of road collisions as well as legal and illegal hunting. The remaining bears learned that roads were dangerous and avoided them, increasing the impacts of roads since the available habitat was greatly reduced. While closure of the existing Husky access road to the public was supported by some interveners, it was suggested by others that locked gates on roads had only a marginal level of effectiveness in reducing public use and, therefore, on the roads' impact. Even if the gate was successful in reducing public traffic, the traffic from Husky's operations would still result in avoidance of the road since bears in the area would have had negative experiences with other nearby road systems. Since grizzly bear habitat has already been lost or degraded throughout much of the East Slopes, further displacement would lead to an ongoing, incremental decline in a population which is already threatened. Other mammal species could be expected to show similar impacts.

With regard to impacts on fish, it was argued that silt deposition into surrounding drainages was an inevitable result of road construction. This too would lead to incremental degradation of already severely damaged aquatic habitat. Spills into area drainages were also identified as a significant risk to aquatic habitat and therefore to fish populations. It was argued that native cutthroat trout and bull trout populations were particularly vulnerable since these species had already been highly impacted by human activities.

The Board believes it must address two questions with respect to the environmental impact of Husky's proposal. The first is whether the environmental value and/or sensitivity of the Moose Mountain region is sufficiently high that any environmental impact from the proposed wells would be unacceptable. Should the Board determine that this is not the case, the second question is whether the amount of environmental impact from the sites and associated development proposed by Husky is acceptable.

The Board believes that the recent changes to the purposes section of the Act did not fundamentally change its mandate, insofar as the Board is charged with balancing and fairly assessing a broad range of public interests with respect to a particular project. In the Board's mind, the changes to the Act simply confirm that the environmental, social, and economic effects of development are among the parameters which must be addressed in determining whether a proposed project is in the public interest. The Board takes note that the legislative changes did not give precedence to these issues over the other purposes of the Act, which include public safety, the prevention of pollution, the conservation of the energy resource, and orderly and efficient development. The Board believes that its mandate requires that it give varying weight to each of these factors appropriate to the specific facts in each case in order to determine whether any specific development is in the public interest.

In this instance, the Board has been asked to deny the applications in order to protect regional terrestrial and aquatic habitat and therefore the species which depend on that habitat. It was argued that any further impact on this habitat is unacceptable. With respect to terrestrial habitat, and particularly grizzly bear habitat, the Board accepts the contention by both applicant and intervener alike that even the delineation stages of this project will have a negative impact, possibly permanent, on the value of this area for grizzly bears and, albeit to a lesser extent, other wildlife as well. Although not discussed in any detail by the interveners, the Board also believes that the development may have a negative impact on the aesthetics of the area and possibly on some associated recreational values. With respect to aquatic habitat, the Board is much less convinced of the potential severity of any impacts, but is willing to accept that there is some risk, however small.

The Board agrees with the position of the Wildlife Foundation that the largest impacts from development in areas such as Moose Mountain often comes from road development rather than directly from the activity (e.g. an oil or gas well). The Board also agrees that closure of the road to public access is at best only partially effective in reducing the impacts of the road. The Board accepts that many species of wildlife will tend to avoid roads with any level of traffic, thereby reducing the amount of usable habitat and that, furthermore, the public and particularly hunters are often very skilled at avoiding or skirting barriers such as gates.

The Board also accepts that there has been a shift in public values which has resulted in a greater emphasis by the public on the protection of wildlands and of the ecological integrity of these areas. IL 93-9 was in fact intended in part to advise industry of this perceived shift in public attitudes, particularly for the East Slopes regions. However, the Board does not accept the contention that the public now automatically values protection over development, any more than the Board accepts the view held by some that development should proceed regardless of the environmental impacts. Nor does the Board believe that the purchase of mineral rights confers an automatic right to a company to exploit those minerals. This can be seen in the need to also obtain permission, at least on Crown lands, from the government for surface access and ultimately from the Board to drill for and to remove any oil or gas discovered. The Board also notes, however, that no legislation is now in place in Alberta which would normally preclude Husky for environmental or similar reasons from exploring for oil and gas in the Moose Mountain area.

In the Board's view, the broader position being brought forward by the interveners (i.e. that the natural values of the Moose Mountain area far outweigh the potential economic benefits of oil and gas development) is premature. At this time, the Board has no reasonable estimate of the area's economic value should oil or gas be discovered and, as was agreed by all parties, only a very preliminary description of its other values, including agricultural, recreational, forestry, and wildland values. Without the development of the two delineation wells, and the provision of a more detailed description of the other potential uses of this area, the Board is unable to fully weigh the potential costs and benefits of oil and gas development in this area.

The Board is not convinced that if it permits Husky to delineate the extent of its discovery, the impacts would be of such significance as to override potential benefits. The Board accepts that there is some risk to the area grizzly bear population during the delineation phase, but does believe, in the event delineation proves that the area does not contain economic oil and gas reserves, that these impacts are reversible. With respect to other environmental impacts, the Board believes with careful planning and construction during the delineation phase that these can either be avoided or mitigated adequately.

With respect to Husky's proposed development plan, the Board accepts that Husky has attempted, within the topographic and geologic constraints it faces, to minimize surface impacts. The Board agrees that, should the project become commercial, the ability to drill multiple wells from a single pad would be environmentally beneficial. The Board also agrees that construction of all access roads and possibly pipelines from a single direction (i.e. the north) appears to have a long-term environmental benefit. The Board notes that while there is some uncertainty as to whether the access road to Pad 2 was within Zone 1 or Zone 5, the final road location was considered acceptable to the Crown, the surface owner, as evidenced by the issuance of the MSL and LOC.

The Board does support the intervener's position that broad-range planning is needed to ensure that human activities do not have an unacceptable impact on the natural values of the East Slopes or on their overall ecological integrity. The Board can also accept that the province is on the early portion of the learning curve on how to do so, and further, that it is imperative that such a process, including the basic research needed to support it, be undertaken in a timely fashion. The Board has viewed IL 93-9 as one initial component of such a process. The Board also notes programs such as Special Places 2000 which could have a significant potential to assist in this planning process. The Board does not believe that the denial of an individual application is an appropriate response to the broader needs for ongoing planning. In fact, insofar as Husky has, as per IL 93-9, coordinated its activities with other energy industry operators in the region in order to minimize regional environmental impacts, the Board views this as a positive step towards ensuring that an effective planning approach occurs for all developments in environmentally sensitive areas of the province.

9 TRADITIONAL USE OF MOOSE MOUNTAIN

The Tsuu T'ina Nation argued that Husky had not in any way addressed the impact of its development on native hunting in the Moose Mountain region. A similar concern was raised regarding potential use of the mountain for spiritual purposes. At the hearing, the Tsuu T'ina Nation testified that approximately 6 months would be required for it to document the extent of native hunting and at least 1 to 1.5 years would be required to document the spiritual use of the area by its members. The Tsuu T'ina Nation argued that because of inadequate time to prepare for the hearing, it could only confirm that the area was used for hunting and for religious purposes, but could not comment on the extent of any impacts from the proposal. The Tsuu T'ina Nation suggested that the application must be denied or at least deferred until adequate consultation had occurred to address its concerns. It was argued that protection of native rights was paramount to meeting other planning objectives for the area set out by either the Board or by the Government of Alberta. The Old Sarcee Band, Uterus Clan, appeared to have a position similar to that taken by the Tsuu T'ina Nation. However, its failure to either speak to its intervention or to provide final argument made it impossible for the Board to confirm this.

The Tsuu T'ina Nation was also concerned that the construction of new access roads could result in the disturbance of existing trail systems, many of which were linked to their spiritual use of Moose Mountain. Because these trails were not recorded, it was felt that new road construction could break up the memorized pathways and make it impossible for their users to follow their traditional trails. The Tsuu T'ina Nation also argued that the locked gate infringed on the right of its members to hunt in the area.

With regard to impacts on native hunting, the Board can accept that the members of the Tsuu T'ina Nation hunt in the Moose Mountain area throughout the year. The Board notes that the Tsuu T'ina Nation did not argue that it was guaranteed the right to be successful in hunting, only the right to hunt. The Board can accept that the Husky proposal may alter hunting success but received no evidence as to the extent this would occur. The Board does not believe the Husky proposal will significantly curtail the ability of the Tsuu T'ina Nation to hunt. With the exception of the actual wellsites, which would clearly no longer be defined as unoccupied Crown lands, the opportunity for members of the Tsuu T'ina Nation to hunt in the area would not, in the Board's view, be reduced by Husky's proposal.

As to the potential impact of the development on native spiritual use of the area, the Board was unable to determine that this would occur, or the extent of such impacts should they occur. At the hearing little evidence was provided to substantiate that such impacts would result from either the existing or proposed development. The Board respects the position of the Tsuu T'ina Nation that such information is normally held in strictest confidence among its members. The Board, however, can only deal with information which is provided equally to all parties with a legitimate interest in a particular issue. The Board notes that the original pad and access road were developed during the winter of 1992 on lands which the Tsuu T'ina Nation considered sacred. Despite this, witnesses for the Tsuu T'ina Nation noted that they had, to the date of the hearing, received no instructions from either the Chief or Band Council to initiate the long and complex process of collecting the information needed to establish the degree to which either the existing or the new development would impact on native spiritual use of the area. As a result, the Tsuu T'ina Nation was unable to provide any clear evidence regarding the extent of spiritual impacts other than to state that they would occur. It further suggested that a minimum of 1 year would be needed to collect such evidence. Given these facts, the Board does not believe it would be correct to deny the application on the basis of an unsubstantiated concern.

10 PUBLIC SAFETY

A concern was raised by several interveners at the hearing regarding possible risks to public safety. This concern arose because of the presence of H_2S (i.e. sour gas) in the oil found by Husky.

At the hearing, Husky filed a copy of its Emergency Response Plan. Husky noted that, based on its calculation of likely sour gas release rates, such a plan would not normally be required under Board regulations. Despite this, the company decided that such a plan would be worthwhile from a public safety perspective. The plan set outs detailed information on the proposed well development program, potential area users, the structure of Husky's emergency response team, and the response procedures which would be followed in the event of an emergency.

At the hearing, the Bragg Creek Environmental Coalition indicated that its earlier concerns regarding public safety had largely been addressed through its discussions with Husky. Other interveners, however, continued to question several aspects of Husky's ability to protect public safety in the event of a sour gas release. In particular, they questioned how Husky would be able to know about overnight use of the area and, should an emergency occur, how Husky would be able to either advise these users of an emergency or to evacuate them successfully. The interveners also questioned whether there might not be some risk, should a subsurface release of sour gas occur, to members of the public who were exploring the Moose Mountain ice caves.

The Board appreciates how public concern may arise at any time that drilling of a well containing sour gas is proposed. Sour gas can be dangerous at even quite low concentrations. It is for this reason that the Board has instituted a broad range of requirements for any company drilling in areas where sour gas may occur. These measures focus first on ensuring that an accidental release does not occur (e.g. blowout preventers) since the Board sees this as clearly the best way to protect public safety. In the event an accident does occur, the Board has instituted a number of requirements to reduce the risk of public exposure to sour gas.

There is no question that the Husky well represents some risk to public safety. The Board believes, however, that these risks are very small and certainly not greater than those posed by similar energy developments containing sour gas throughout the province. The Board accepts that Husky's proposed drilling program meets the criteria set out by the Board to protect public safety and notes that Husky has gone considerably further in this direction (i.e. preparation of an Emergency Response Plan) than would normally be required. The Board, therefore, does not believe that Husky's proposal represents an undue risk to public safety.

11 GREENHOUSE GASES

In its intervention, Green Peace claimed that the Husky application was deficient in that it neither provided an estimate of its potential greenhouse gas emissions nor indicated the manner in which it would mitigate the impact of those emissions. Since Canada was a signatory to an international agreement to stabilize greenhouse gas emissions, Green Peace argued that Husky and the Board were obliged to ensure that their actions were consistent with the federal agreement.

In response to questioning, Green Peace advised the Board that it was unaware of any legislation (federal or provincial) which obliged either a company or an administrative tribunal to comply with the undertakings made by the federal government with regards to greenhouse gases. The Board believes that the appropriate manner of addressing the undertakings of the federal government in this regard is an issue which must be first resolved by Canada and the provinces. The Board is not prepared to require an individual company to attempt to address this issue in advance of those discussions and in the absence of any policy direction from government.

12 DECISION

Having considered all the evidence, the Board concludes that the proposed wells are in the public interest and that the methods of accessing, drilling, completing, and testing the wells, as described, will allow the proposal to proceed without unacceptable impacts on the natural environment and on the other users of the Moose Mountain area. The Board will expect Husky to honour the commitments made at the hearing with regards to well testing procedures and ongoing public consultation, particularly with the Tsuu T'ina Nation. The Board is therefore prepared to approve Applications No. 931689, 931696, 931746, 931747, and 931748. Accordingly, the well licences will be issued in due course.

DATED at Calgary, Alberta, on 11 March 1994.

ENERGY RESOURCES CONSERVATION BOARD

B. F. Bietz, Ph.D., P.Biol.
Board Member

R.G. Evans

R. G. Evans, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Board Member

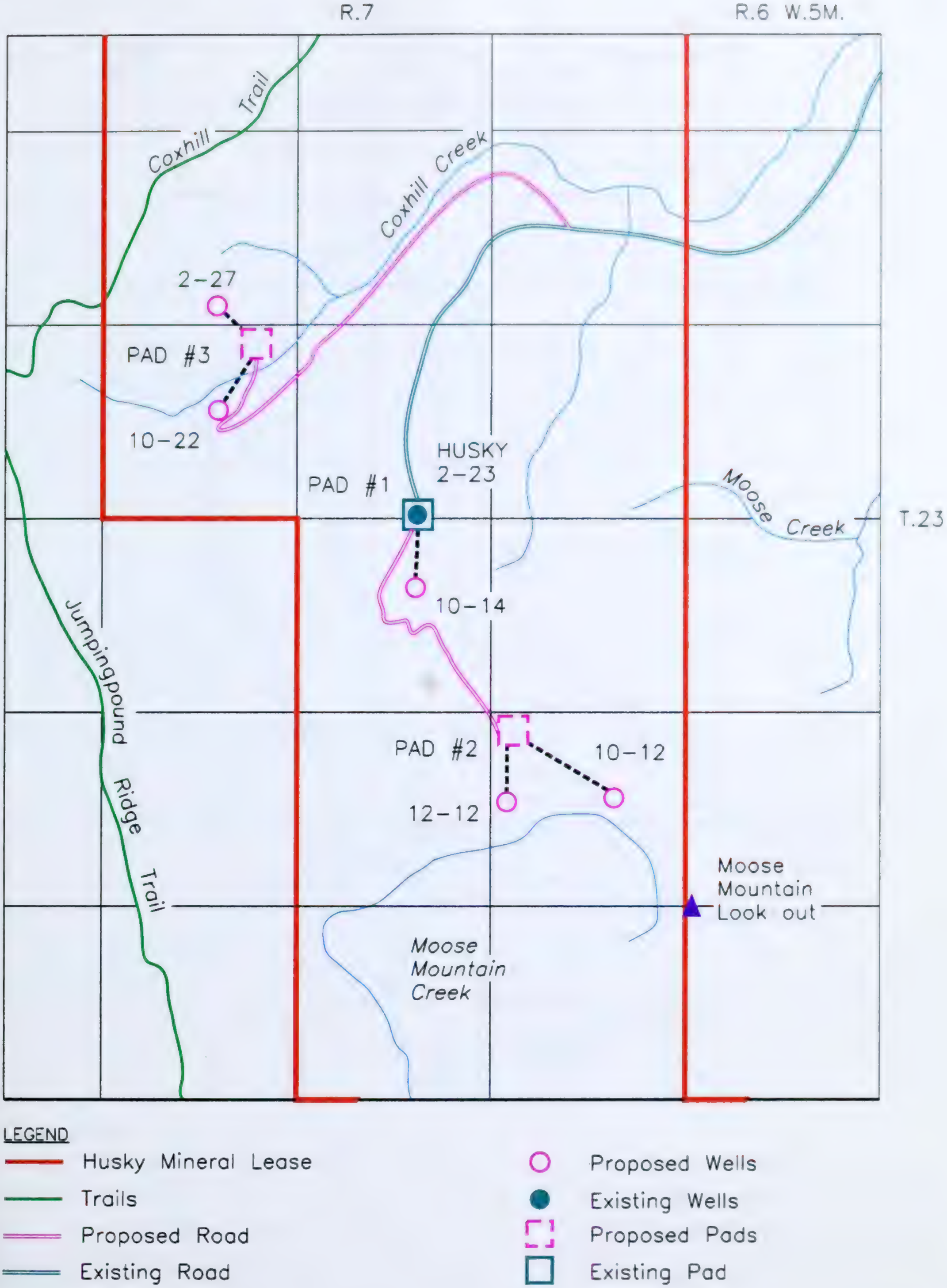


FIGURE 1
MOOSE MOUNTAIN
Application No. 931689, 931696, 931746,
931747 & 931748
Husky Oil Operations Ltd.

D 94-2
ERCB

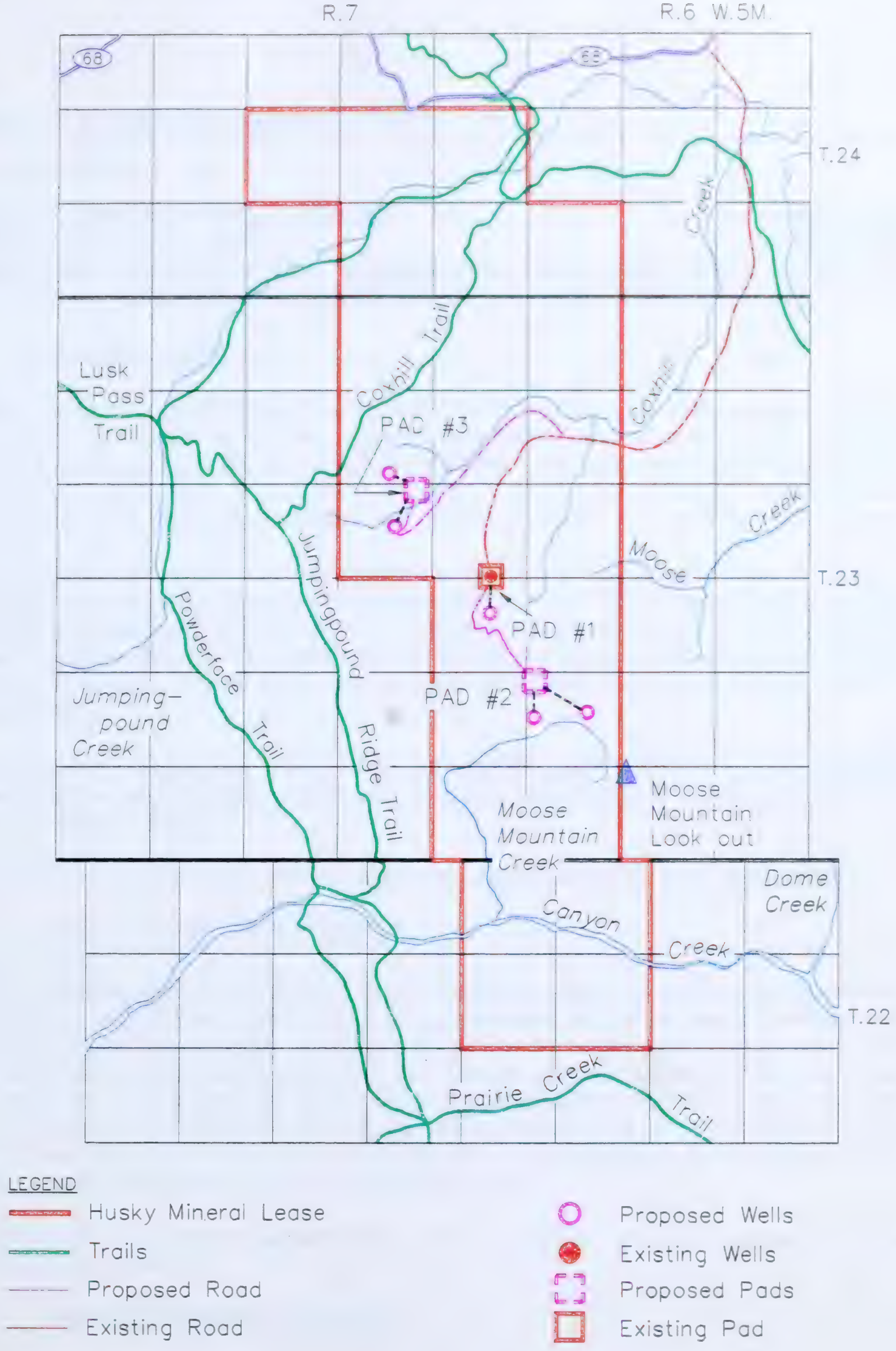


FIGURE 2
MOOSE MOUNTAIN
Application No. 931689, 931696, 931746,
931747 & 931748
Husky Oil Operations Ltd.

D 94-2
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR WELL LICENCE — Memorandum of Decision
MOOSE MOUNTAIN AREA — Pre-Hearing Meeting
HUSKY OIL OPERATIONS LTD. Applications No. 931689, 931696, 931746, 931747 and 931748

1 INTRODUCTION

Husky Oil Operations Ltd. (Husky) has applied to the Energy Resources Conservation Board (the Board) for well licences for five wells proposed to be drilled from surface locations in Lsd 2-23-23-7 W5M, Lsd 13-12-23-7 W5M, and Lsd 16-22-23-7 W5M. The wells would be known as HUSKY RIGEL MOOSE 10-14-23-7, 12-12-23-7, 10-22-23-7, 2-27-23-7 and 10-12-23-7. The purpose of the wells would be to explore the immediate area to obtain production from the Turner Valley Formation.

The Board was aware that a number of parties had concerns with these applications. To satisfy itself that parties which may be affected had the opportunity to set out their positions, the Board directed that the applications be advertised and a pre-hearing be meeting held to receive submissions as to the need for a public hearing. The notice issued by the Board noted that, if necessary, a hearing would be held on 11 January 1994 and submissions respecting the hearing were to be filed on or before 4 January 1994.

The pre-hearing meeting was convened at the offices of the Board in Calgary on 2 December 1993. The Board members presiding at the meeting were F. J. Mink, P.Eng., B. F. Bietz, Ph.D., P.Biol., and N. G. Berndtsson, P.Eng.

The names of the participants who registered at the meeting are shown on the attached list.

2 VIEWS OF THE APPLICANT

Husky submitted that it believed, based on the submissions already received, that the Board would find it was appropriate to hold a public hearing of its applications, and that the matter should proceed as advertised in the Board's notice. Respecting the need for further information, Husky noted that it was at risk. Husky advised that, as applicant, it would supply information it believed relevant to support its application. This information would be reviewed at the hearing and Husky would then be subject to the decision of the Board as to its adequacy. Husky submitted that all parties should be aware of and adhere to the Board's ERCB G-31, Guideline Respecting Applications For Local Interveners' Costs Awards, with respect to funding and intervener status.

Rigel Oil & Gas Ltd. (Rigel) supported Husky in its submissions relating to the matters considered at the pre-hearing meeting.

3 VIEWS OF THE INTERVENERS

The Wildlife Foundation (the Foundation) argued that the Board should decide at the outset of the meeting if it would require a public hearing. Further if a hearing was to occur, the Foundation felt it would be appropriate to reschedule the hearing to 25 January 1994 in order that the Foundation could properly prepare its submission. Besides some specific matters, its approach would be to review the application on an ecosystem basis by considering cumulative effects. The Foundation also requested that, irrespective of whether or not they made application for funds, they be recognized as an intervener.

The Rocky Mountain Ecosystem Coalition (the Rocky Mountain Coalition) supported the position by the Foundation that a hearing be held and that it be rescheduled to a later date in January in order that submissions could be adequately prepared by interveners. The Rocky Mountain Coalition submitted that as well as having specific concerns with the applications, it believed that cumulative effects and ecosystem management also must be addressed by Husky and the Board. This should be accompanied by an environmental impact assessment to acquire the appropriate baseline data sufficient to allow the Board to integrate the impacts of the specific project within a broader framework. The Rocky Mountain Coalition would also be seeking standing as an intervener at the hearing.

The Bragg Creek Environmental Coalition (Bragg Creek Coalition) submitted that as area residents they were concerned about the cumulative effect of the proposed development on the region. They also had specific concerns regarding public safety, impacts on wildlife habitat, and recreation, and the mitigative measures which should be applied. The Bragg Creek Coalition submitted that it would also be requesting intervener status.

Mr. Fred J. Fraser on behalf of the Old Sarcee Band, Uterus Clan (the Band) supported the request for a postponement of proceeding in order to allow sufficient time to arrange for the appearance of witnesses. The Band submitted that the impact caused by oil and gas activities on the environment was of great concern to them. To address their concerns the Band submitted that it was appropriate that the Board call for a public hearing for which they would be requesting local intervener status.

4 VIEWS OF THE BOARD

After considering the opening remarks of all participant parties the Board agreed that some of the interested parties may be affected by the application and the applications should be set down for a public hearing. The Board accepts the interveners arguments for rescheduling of the hearing and does not believe the modest extension requested would have an onerous impact on the applicant. The Board therefore intends to convene the hearing of these applications on 24 January 1994. Submissions to the Board must be filed no later than 17 January 1994. A notice of rescheduling will be issued in due course. The Board would expect that all parties observe the specified filing date and present all material which they wish to have considered at the hearing by this time. Material filed after this date may not be accepted for consideration at this hearing.

The Board would also confirm that all parties who presented positions at the pre-hearing meeting will be recognized to participate in the hearing.

Respecting matters of local interveners status and funding, the Board believes the appropriate procedures are set out in the Board's document G-31, Guideline Respecting Application For Local Interveners' Costs Awards and will rely on this mechanism to address the issue. In the interests of conducting an orderly hearing, the Board encourages parties with similar interests to work cooperatively in addressing issues.

With regards to the scope of the hearing, the Board accepts the Husky position that it is the applicant which must supply the appropriate material to support its applications. The Board will rely on this material to determine its adequacy in supporting the applications and therefore, it is the applicant which is at risk if insufficient evidence is provided. In turn, the Board also expects interveners to ensure that their submissions are of relevance to the applications and to the legislated mandate of the Board.

DATED at Calgary on 9 December 1993.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

N. G. Berndtsson, P.Eng.
Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Representatives
Husky Oil Operations Ltd. (Husky)	F. M. Saville S. Purcell
Rigel Oil & Gas Ltd. (Rigel)	K. F. Miller
The Wildlife Foundation (the Foundation)	Dr. B. L. Horejsi
Rocky Mountain Ecosystem Coalition (the Rocky Mountain Coalition)	M. Sawyer
Old Sarcee Band, Uterus Clan (The Band)	F. J. Fraser
Bragg Creek Environmental Coalition (Bragg Creek Coalition)	C. G. Docken
Energy Resources Conservation Board staff	R. D. Heggie R. Creasey, P.Biol. N. F. Lord

CARDINAL RIVER COALS LTD.
PERMIT EXTENSION TO INCLUDE 50-A8 PIT

Decision D 94-3
Application No. 931225

1 INTRODUCTION

1.1 Application

Cardinal River Coals Ltd. applied, under Part 4 section 10(1)(b) of the Coal Conservation Act, for an extension to Permit No. C 92-17 to include the 50-A8 development as shown in Figure 1.

1.2 Interventions

Interventions to the application were received from Mrs. Barbara A. Higgins, a resident of Cadomin, Alberta and from her son, Mr. John Higgins. The interventions raised concerns regarding the impacts of the proposed development on Mrs. Higgins' health, quality of life and the environment.

1.3 Hearing

The application was considered at a public hearing in Hinton, Alberta on 14 March 1994, before Vice Chairman F. J. Mink, P.Eng., Board Member Dr. B. F. Bietz, P.Biol. and Acting Board Member C. A. Langlo, P.Geol. Those who appeared at the hearing and abbreviations used in this report are listed on the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Cardinal River Coals Ltd. (CRC) R. C. Secord	W. Hume, P.Eng. F. J. Munn, P.Eng. L. R. LaFleur, P.Eng. R. J. Logan, P.Ag. D. J. Whicker, P.Eng. P. G. Sagert, P.Eng. A. Wolanski, M.Sc., P.Biol. J. A. Kupper, Ph.D. R. Ferster, R.P.F., P.Biol. B. MacCallum, P.Biol. A. F. Stewart, P.Eng. W. A. Crosby, Ph.D., P.Eng.
B. Higgins (Higgins) J. Higgins	B. Higgins J. Higgins H. Ready

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Environmental Protection (AEP) G. Van Nes	
Energy Resources Conservation Board staff D.I.R. Henderson, P.Eng. G. Kozokowsky, P.Eng. S. Kassam	

1.4 Background

CRC initially proposed development of the 50-A Baseline area in 1989. The proposal involved the development of three surface mines (A6, A7 and A8 pits) in an eastward direction towards the community of Cadomin. The new pits would extend over a series of ridges which had previously separated the main CRC development from the hamlet. The public involvement program at that time revealed some opposition to the proposal, particularly the A8 pit which would be proximal to Cadomin. As a result, CRC postponed its plans for the A8 pit and concentrated on discussing plans for the A6 and A7 pits with the residents of Cadomin. An application for the A6/A7 permit extension was filed with the ERCB in August 1990.

Following an open house meeting in December 1989, the residents of Cadomin formed the Cadomin Environmental Protection Association (CEPA). This organization retained legal and technical assistance to advise it on impacts of CRC's development proposals on the community.

In October 1991, the Board approved CRC's application for development of the A6 and A7 pits subject to the establishment of a community advisory committee, including representation from CEPA, which would review the environmental and reclamation aspects of the A6 and A7 surface mines and advise the ERCB and AEP. CEPA has also continued to take an active role in the review of CRC's application for the proposed 50-A8 development. Prior to the hearing CEPA advised the Board that its discussions with CRC were continuing and that it did not intend to intervene to oppose the A8 mine permit application.

2 ISSUES

After careful review of the evidence presented, the Board believes the issues to be addressed are:

- the need for the expansion, and
- the impacts of the expansion on the area environment, including:
  - noise
  - dust
  - water, and
  - aesthetics.

3 VIEWS OF THE APPLICANT

CRC noted that it had established an excellent reputation, in a very competitive marketplace, as a reliable source of high quality coal. This included recently obtaining markets for medium volatile coal for which A8 represents a unique source. CRC stated that development of the A8 mine was essential to meet its contractual obligations for medium volatile coal during 1994/96 period since contracted volumes could not be met from within the existing minesite. It argued that the only available source of medium volatile coal is from the 50-A Baseline area, and that the other sources in this region were not sufficiently developed to be available in the required timeframe. CRC submitted that the failure to meet its contractual obligations would probably result in a permanent loss of contracts in the highly competitive world of metallurgical coal markets. CRC noted that development of the A8 pit would also help to extend the life of the mine, and therefore the economic benefits accruing to both regional and provincial economies.

CRC noted that it intended to modify the mine plan for A8 based on the exploration drilling programs in A8 and mining experience in developing A7 in order to reduce the impact on the Hamlet of Cadomin. The current application called for fewer pits (2 versus 3) and a commitment to set back the mine at least 152m (500 feet) from the Hamlet boundary. The revised mine plan also reduced the area to be disturbed from 164 to 78 hectares (404 to 193 acres). At the hearing, CRC acknowledged it had an agreement with CEPA that land disturbance would be no closer than 700 feet to the boundary of the Hamlet and confirmed that it would have no difficulty if the Board approved the permit boundary at that distance. With respect to the coal resources contained in the adjacent Manalta Coal Ltd. lease, CRC stated that, although it had originally proposed to recover some of this coal, the high strip ratio made this uneconomic.

CRC submitted, as one component of its application to the ERCB, an Environmental Impact Assessment (EIA) which it had prepared pursuant to requirements set out by AEP. The EIA showed that the potential for noise, dust, and water related impacts on the residents of Cadomin were small and within the guidelines established by existing regulations. CRC also indicated that it had extensive experience in carrying out reclamation at high altitude and noted that its current reclaimed areas supported a large mountain sheep population. In response to public concern CRC had developed a series of corporate policies which were intended to further demonstrate its commitment to protect the residents of Cadomin from negative environmental impacts. At the hearing CRC re-stated its commitment to fulfilling these policies.

CRC noted that it planned to take a number of specific actions to maximize mitigation of impacts. These included: use of revised blasting procedures and blast timing to reduce overall noise levels, an aggressive dust control program, creation of sound barriers, establishment of monitoring programs for noise, dust and water impacts, and a complaint-response policy. Its water policy outlines in clear terms that CRC would proactively replace or restore any source of water to the residents that may be disrupted by its mining in the area. CRC committed to undertaking reclamation of the A8 minesite as soon as possible. Future reclamation programs at the site would have a greater emphasis on establishing more tree cover, especially on those areas that would be most visible from the community, than reclamation programs on other portions of the minesite. CRC also noted that the impacts from development of the A8 pit would be of relatively short duration with the most significant visual and noise impacts occurring over the next 2 years. It estimated completion of mining of the A8 pit by May 1996 and full reclamation by 1998.

4 VIEWS OF INTERVENERS

The Higgins did not question the relative economic importance of the proposed development to CRC. However, they expressed strong concerns about the proximity of the proposed activities to the Hamlet and the impacts of the development on Mrs. Higgins' use and enjoyment of her property. In their view, the economic benefit to be derived from open pit mining near to Mrs. Higgins' home did not outweigh the potential costs to her health and to the local environment.

Mrs. Higgins stated that she was opposed to the granting of the application since it represented a further intrusion on her lifestyle. She submitted that she could already hear blasting and equipment noise from the existing operations at the A7 pit and felt that this could only be more pronounced with the new development as the A8 pit would be much closer to her residence. She was highly sceptical with respect to CRC's claims that its proposals would not significantly affect her quality of life and her health, that the disturbance to the land would not adversely impact her water supply, and that the waste rock dumps would not present a safety hazard. Mrs. Higgins also expressed reservations about CRC's ability to carry out an effective reclamation program at altitudes in excess of 5000 feet.

Mr. John Higgins stated that he was also opposed to the granting of the application. He submitted that dust emissions from the proposed development, together with the emotional stress of having the activities close to her residence, could exacerbate his mother's asthmatic condition.

5 VIEWS OF THE BOARD

The Board has reviewed the evidence submitted by CRC and is satisfied the proposal meets all the technical and environmental standards normally imposed for such operations.

The Board is willing to accept CRC's contention that the A8 mine would be needed to allow the company to successfully meet its contractual obligations in the short term. The Board believes that in the absence of alternative sources of supply, a loss of the A8 mine could impose some economic hardship to CRC and to the province. It notes that development of the A8 mine will extend the overall mine life and will result in economic benefits to the Cadomin region. Based on these factors the Board believes that there is a need for the project. The Board has also reviewed the information filed and accepts that, given the high ratio of overburden to coal within the Manalta lease, it would not be economic to include this area within the proposed mine permit boundary.

The Board believes that the main issue to be determined is whether the environmental and social impacts of the development can be sufficiently mitigated so that the project benefits outweigh the costs. The Board believes that CRC has carried out an effective community awareness program to ensure residents are aware of the proposed development and has made a sincere effort to communicate with the residents of Cadomin in order to address their concerns. The Board considers the EIA as a reasonable description of the potential environmental impacts and the likely duration and magnitude. In general, the Board believes that the mitigation measures proposed by CRC should be effective in reducing or eliminating most impacts and community concerns resulting from the mine development. The Board expects CRC to rigorously enforce the policies adopted to further reduce impacts and believes that the proposed monitoring programs should be effective in identifying unforseen problems and allowing CRC to respond.

Notwithstanding CRC's good intentions, the Board does accept that there is some increased risk of environmental impact from the A8 mine on Mrs. Higgins. The Board finds it unlikely that there will not be some general increase in noise levels at her residence, particularly at night. The Board does believe, however, that CRC can, with careful planning and monitoring, ensure that noise is kept to an acceptable level within the current guidelines and should not unduly reduce her quality of life. The Board believes that a similar situation exists for dust problems. Given Mrs. Higgins' particular health problems the Board expects CRC to show ongoing sensitivity to those concerns.

CRC has generally satisfied the Board that dust emissions can be kept within the Provincial guidelines for particulates. The Board notes that both a noise and a dust monitoring program are to be established and that CRC has a "complaint response" policy which residents can use to identify problems and obtain the appropriate action. The Board also notes that both noise and dust impacts, if they occur, will be intermittent and of relatively short duration until the pit is depleted.

The Board is also satisfied that the impacts on water supplies, with the exception of the Inland Cement houses, are likely to be minimal. It notes that CRC has instituted a water replacement policy for instances when residents of Cadomin consider problems do arise with respect to water quality or quantity. The Board accepts the evidence provided by CRC that Mrs. Higgins' water supply should not be at significant risk from the development of the A8 pit. The Board would urge CRC to develop an adequate monitoring program, prior to development of the A8 pit, to allow both parties to be assured that the water supply does remain unaffected.

The Board notes that reclamation has been carried out satisfactorily in adjacent areas of the CRC mine. The Board agrees with Mrs. Higgins that surface mining will significantly alter the areas' surface features. This is an inevitable consequence of surface mining in complex terrain. However, the Board notes that the ultimate landscape will reclaim the scars left by previous underground mining and can incorporate features of interest to local residents. Furthermore, the Board does not accept that the reclaimed landscape, while different, will be less aesthetically pleasing than the existing landscape. The Board recognizes that restoring the landscape will take time and expects that AEP and CRC will ensure, through the Conservation and Reclamation Review process, that this takes place as rapidly as possible.

6 DECISION

Having considered all the evidence, the Board finds the proposed expansion of pit A8 meets all regulatory requirements and is in the overall public interest. The Board approves the application subject to the undertakings by CRC and subject to the mine permit boundary being located no closer than 700 feet from the boundary of the Hamlet of Cadomin. The Board expects that every effort will be made to complete mining and reclamation in as short a time as possible in order to reduce the time in which the residents of Cadomin could be impacted by the project.

DATED at Calgary, Alberta, on 5 April 1994.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

Dr. B. F. Bietz, P.Biol.*
Board Member

C. Langlo, P.Geol.*
Acting Board Member

---

* Dr. Bietz and Mrs. Langlo were unavailable for signature but concur with the contents and with the issuing of this report.

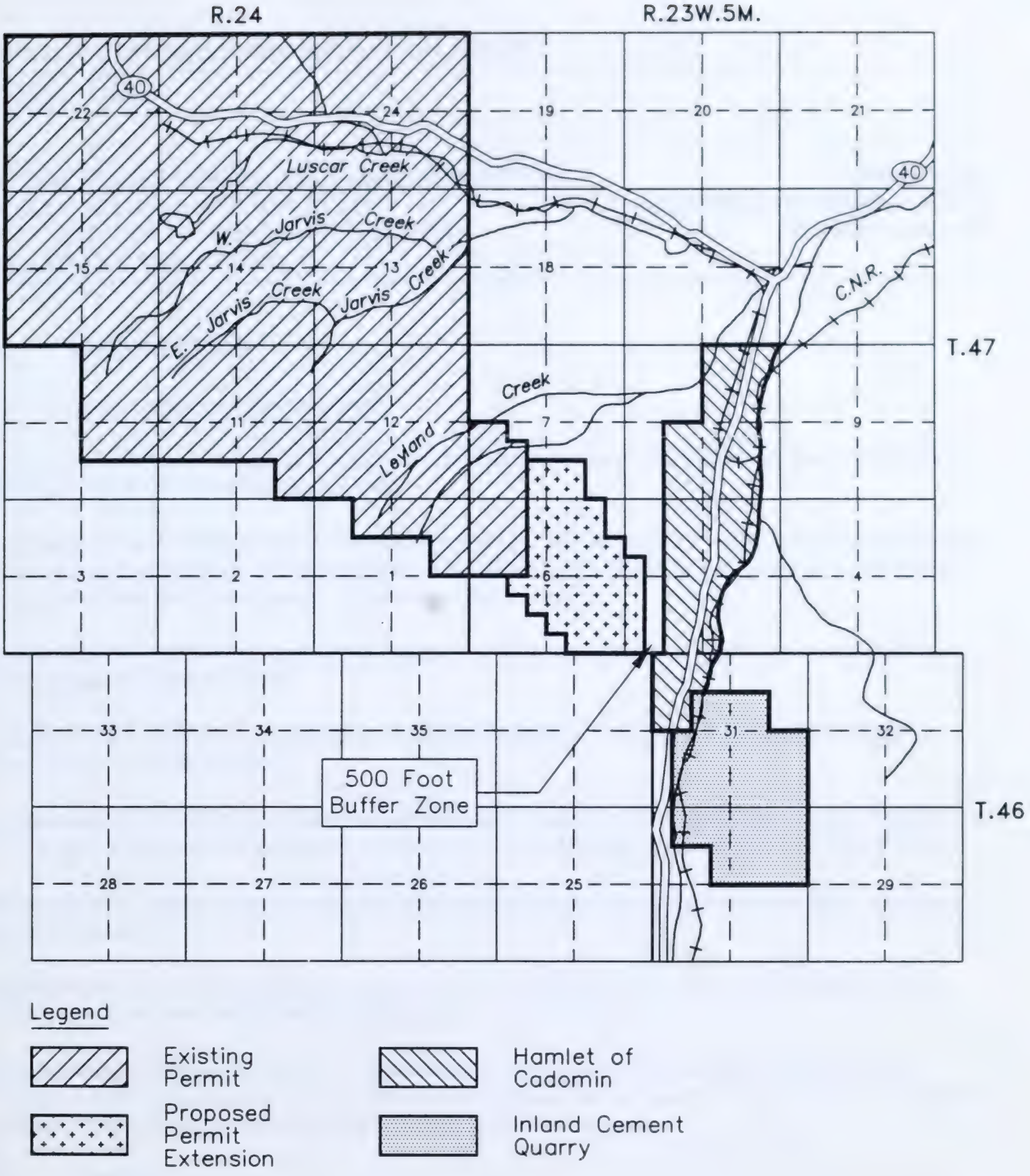


FIGURE 1

LUSCAR AREA

Application No. 931225

Cardinal River Coals Ltd.

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATIONS FOR ESTABLISHING A HOLDING, WELL LICENCES AND RELATED PIPELINE AND PRODUCTION FACILITIES DISCOVERY WEST CORP.

Decision D 94-4
Applications No. 931807 to 931818
and 940304 to 940308

1 INTRODUCTION

1.1 Applications and Interventions

Discovery West Corp. (Discovery) applied to the Energy Resources Conservation Board (the Board) for approval of the following applications:

Applications No. 931807 to 931818 inclusive for twelve well licences for wells proposed to be drilled from two surface locations in the north half of Section 17-38-3 W4M, for the purpose of obtaining production from the Dina Member of the Mannville Formation;

Application No. 940304 for approval to construct and operate a temporary oil battery at Legal Subdivision 10-17-38-3 W4M;

Application No. 940305 for approval to construct and operate a temporary oil battery at Legal Subdivision 16-17-38-3 W4M;

Application No. 940306 for approval to construct and operate an oil well battery at Legal Subdivision 13-16-38-3 W4M and two associated test facilities at Legal Subdivisions 10 and 16-17-38-3 W4M;

Application No. 940307 for approval to construct two pipelines associated with the above captioned application; and

Application No. 940308 to establish a holding in the north half of Section 17-38-3 W4M for the production of oil from the Mannville Group.

Interventions to these applications were submitted to the Board by the surface landowners, the Hansons, on whose land the subject facilities were proposed to be located. Letters were also filed by a number of area residents supporting the interventions of the Hansons.

1.2 Hearing

A public hearing of the applications was held in Provost, Alberta on 21 June 1994 before a division of the Board comprised of Board Member R. G. Evans, P.Eng., and Acting Board Members C. A. Langlo, P.Geol., and W. G. Remmer, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals & Representatives (Abbreviations Used in Report)	Witnesses
Discovery West Corp. (Discovery)	
B. K. O'Ferrall	B. Berrien
	J.A.D. Boone
	D. R. Sharpe, P.Eng.
	W. Boddy, P.Eng.
The Hansons	
J. W. Bodnar	Roy Hanson
	Thelma Hanson
	Bill Hanson
Energy Resources Conservation Board	
M. J. Bruni	
B. A. Austin, P.Geol.	
B. B. Boyd	
N. F. Lord	
R. S. King	

2 CONSIDERATION OF THE APPLICATIONS

At the commencement of the hearing the Board was informed by Discovery that a concerted effort in negotiation between Discovery and the Hansons had resulted in agreement on the outstanding matters between the parties. This agreement was subject to certain amendments and modifications to the applications currently before the Board with the exception of the application to establish a holding which remained unchanged. The agreement was also subject to certain conditions which Discovery was prepared to accept in order that the Hansons' agricultural activity and lifestyle would not be affected to such a degree as to make Discovery's proposal unacceptable.

This arrangement was confirmed by the Hansons who submitted that their agreement should not be construed as satisfaction of their objections, but rather an attempt to compromise with Discovery. Further, it was requested that the Board be made aware of these terms and conditions and that they become part of the public record.

3 VIEWS OF THE BOARD

The Board accepts that the parties have reached a voluntary resolution to the outstanding matters between them. The Board acknowledges the efforts of Discovery, the Hansons, and their representatives in negotiating a settlement. Given this, the Board accepts the conceptual development plan described by the two parties at the hearing and directs its staff to continue processing of the applications upon receipt of the appropriate amendments and modifications to the proposals.

4 CONCLUSION

The Board concludes that once the appropriate material has been filed and all Energy Resources Conservation Board requirements have been met the applications can be approved. Application No. 940308 which was not modified is hereby approved.

DATED at Calgary, Alberta, on 6 July 1994.

ENERGY RESOURCES CONSERVATION BOARD

R G Evans

R. G. Evans, P.Eng.
Board Member

Langlo

C. A. Langlo, P.Geol.
Acting Board Member

W. G. Remmer, P.Eng.
Acting Board Member

Decision D 94-5

ERCB

Syncrude Continued Improvement and Development Project

Mildred Lake Oil Sands Plant

ERCB

Syncrude Continued Improvement and Development Project

Mildred Lake Oil Sands Plant

ENERGY RESOURCES CONSERVATION BOARD
SYNCRUDE CONTINUED IMPROVEMENT AND DEVELOPMENT PROJECT
MILDRED LAKE OIL SANDS PLANT

ERCB Decision D 94-5

Published by:

Energy Resources Conservation Board
640 - 5 Avenue SW
Calgary AB T2P 3G4

Telephone: (403) 297-8311

Fax: (403) 297-7040

TABLE OF CONTENTS

Page

1 INTRODUCTION 1

1.1 Application 1
1.2 Background 1
1.3 Hearing 2
1.4 Issues 3

2 SYNCRUDE POSITION 3

2.1 Technical Issues 3

2.1.1 Production Capability 3
2.1.2 Expansion Project Design and Construction Start Date 4
2.1.3 Bitumen Supply 4
2.1.4 Project Approval Term Extension 7

2.2 Environmental Issues 8

2.2.1 Atmospheric Emissions 8
2.2.2 Reclamation 14
2.2.3 Fine Tails Management Alternatives 17

2.3 Socio-economic Issues 18

3 POSITIONS OF THE INTERVENERS 20

3.1 Technical Issues 20

3.1.1 Production Capability 20
3.1.2 Expansion Project Design and Construction Start Date 21
3.1.3 Bitumen Supply 21
3.1.4 Project Approval Term Expansion 22

3.2 Environmental Issues 22

3.2.1 Atmospheric Emissions 22
3.2.2 Reclamation 28
3.2.3 Fine Tails Management 31

3.3 Socio-economic Issues 32

TABLE OF CONTENTS (cont'd) **Page**

4 BOARD VIEWS 35

4.1 Technical Issues 35

4.1.1 Production Capability 35
4.1.2 Expansion Project Design and Construction Start Date 36
4.1.3 Bitumen Supply 36
4.1.4 Project Approval Term Extension 37

4.2 Environmental Issues 37

4.2.1 Atmospheric Emissions 37
4.2.2 Reclamation 40
4.2.3 Fine Tails Management Alternatives 41

4.3 Socio-economic Issues 42

5 DECISION 43

LIST OF TABLES

1 THOSE WHO APPEARED AT THE HEARING 44

2 ACTUAL AND PREDICTED EMISSIONS 8

3 SYNCRUDE WET AND DRY DEPOSITION PREDICTIONS 11

4 EFFECTIVE ACIDITY DEPOSITION LIMITS 11

5 COMPARISON OF WET AND DRY DEPOSITION PREDICTIONS 25

FIGURE

1 SYNCRUDE OIL SANDS PROJECT MILDRED LAKE AREA 5

1 INTRODUCTION

1.1 Application

In September 1992, Syncrude Canada Ltd. (Syncrude) applied pursuant to section 14 of the Oil Sands Conservation Act to amend its existing Approval No. 5641 for the Mildred Lake Oil Sands Plant. In its application Syncrude sought approval for:

- an increase in its current synthetic crude oil (SCO) production limit from 10.0 to 12.6 million cubic metres per year (10^6 m^3/yr);
- an extension, to 31 December 1997, of the lapse date for an approval to expand the plant to produce an additional 5.0×10^6 m^3/yr of SCO;
- an extension of its approval expiry date from 31 December 2018 to 31 December 2025;
- the processing of bitumen from off-lease sources at its Mildred Lake facility and for shipping of bitumen to other processing facilities; and
- conceptual mining, lease development, and reclamation plans, including fine tailings reclamation.

1.2 Background

The Syncrude project was first approved by the Energy Resources Conservation Board (the Board) in 1968 and commenced production in 1977. The project comprises an open-pit mine utilizing draglines, bucket-wheel reclaimers and conveyors to transport bituminous sands to an extraction plant where the bitumen is separated from the sand using a modified hot water process. Wastes from the extraction plant, which include coarse sand, fine tailings and water, are currently directed to two large tailings sites for temporary storage. The produced bitumen is upgraded to SCO using fluid coking, hydrocracking and hydrotreating processes. By-product sulphur and petroleum coke are also produced.

The Syncrude facility currently has approval to produce up to 10.0×10^6 m^3/yr of SCO. In 1988 approval was granted to add facilities to produce an additional 5.0×10^6 m^3 of SCO annually. The approval stipulated that expansion was to commence by the end of 1992. Due to Syncrude's pending application requesting an extension to this approval, interim amendments to the lapse date were granted in both 1992 and 1993. These interim amendments also approved increases in the annual SCO production limit and authorized Syncrude to process off-lease bitumen in the 1992 and 1993 calendar years. Both interim amendments were made with the agreement of all interested parties.

The 1987 Expansion Project application was reviewed through a consultative process which included representatives of Syncrude, the Fort McKay First Nation, and various regulatory agencies. This group, which became known as the Syncrude Expansion Review Group or SERG, was able to address the issues and concerns of the Fort McKay First Nation without the need for a public hearing process.

A somewhat different approach was used by Syncrude during the preparation of this application. Syncrude identified key stakeholder groups with which it intended to individually consult in order to identify and, if possible, address areas of concern. The key stakeholder groups identified were: the Fort McKay First Nation, the City of Fort McMurray, and various environmental associations. In order to simplify its dealing with the environmental associations, Syncrude approached the Alberta

Environmental Network and asked it to set up a committee of interested organizations. The Syncrude Environmental Assessment Coalition (SEAC) was formed as a result. Separate consultation processes were initiated with each of these three stakeholder groups prior to the filing of the application and continued up to (and in some cases, during) the hearing.

Syncrude filed the first volume of its application with the Board in September 1992. During the next 2 months, three additional volumes of environmental and socio-economic information were filed. On 18 November 1992, the Board issued a Notice of Filing to advise any interested parties that it had received an application from Syncrude. In addition to interventions by the three stakeholder groups with which Syncrude was already consulting, the Edmonton Friends of the North Environmental Society (EFONES) advised of its intent to intervene on behalf of Fort McMurray resident Mr. Jim Rogers.

A pre-hearing meeting was convened by the Board in Fort McMurray on 22 April 1993 to establish a date and location for the public hearing into Syncrude's application and to establish an appropriate deadline for the filing of interventions and supporting documentation.

1.3 Hearing

Syncrude's application was considered by a division of the Board (the panel) at a public hearing in Fort McMurray, Alberta commencing on 8 September 1993 with F. J. Mink, P.Eng. (Chairman), Dr. B. F. Bietz, P.Biol., and R. G. Evans, P.Eng. sitting. At the outset of the hearing a motion to adjourn was made by the Fort McKay First Nation (Fort McKay) and SEAC. They argued that the Board did not have the jurisdiction to proceed with the hearing until Alberta Environmental Protection (AEP) had ruled on the adequacy of Syncrude's environmental impact assessment as required under the provisions of the new Environmental Protection and Enhancement Act. The panel ruled against the motion but agreed to adjourn the hearing for one week while the parties sought leave to appeal the panel's decision in the Alberta Court of Appeal (the Court). Leave to appeal was granted by the Court but, by mutual consent of all parties, the hearing resumed on 20 September 1993 and continued in Fort McMurray until 17 November 1993. Final argument was heard in Calgary, Alberta on 25 and 26 November 1993. Those who participated in the hearing are listed in **Table 1** at the end of the report.

The arguments on the Board's jurisdiction to hear Syncrude's application were heard by the Court on 3 March 1994. In a unanimous decision, the Court confirmed the Board's jurisdiction to proceed with the hearing.

The Athabasca Chipewyan Band 201 filed an intervention opposing Syncrude's application and was represented at the hearing by Mr. J. Slavik. It did not present evidence or conduct any cross-examination.

The following also filed interventions in support of Syncrude's application but did not appear at the hearing:

- CBR Cement Canada Ltd.
- Economic Development Edmonton
- Edmonton Chamber of Commerce
- Stanley Industrial Consultants Ltd.

1.4 Issues

After careful consideration of the evidence presented, the Board believes the main issues fall into three categories: technical, environmental, and socio-economic.

The major technical issues are:

- the production capability of the existing facility,
- the proposed expansion technology,
- bitumen supply, including imports and exports, and
- the need for an extension to the project expiry date.

The major environmental issues are:

- atmospheric emissions and associated impacts,
- fine tails management, and
- fine tails and site reclamation plans.

The major socio-economic issues are:

- employment and business opportunities for local native communities,
- compensation for socio-economic impacts experienced by local native communities, and
- infrastructure concerns in the City of Fort McMurray.

2 SYNCRUDE POSITION

2.1 Technical Issues

2.1.1 Production Capability

Syncrude's Mildred Lake facility is currently approved for SCO production of up to 10.0×10^6 m^3/yr of SCO. Its current application proposes to use the existing facilities to increase SCO production to a maximum of 12.6×10^6 m^3/yr (the staged development). Syncrude argued these rates could be achieved through a combination of increased yields and service factors with some low cost capacity increases through the debottlenecking of existing units. This increase would separate from the previously approved expansion project (Section 2.1.2). By undertaking that project, Syncrude could further increase production by up to another 5.0×10^6 m^3/yr.

To achieve the 12.6×10^6 m^3/yr level of SCO production, Syncrude proposed two operating modes for its bitumen upgrading facilities which it referred to as the 'Base' and 'Once-through' modes. The Base mode would achieve higher production by improving service factors and increasing feedrates to the cokers and hydrocracker. The Once-through mode would also incorporate a higher SCO yield in addition to the foregoing improvements. To achieve this maximum level of production would require hydrocracking feedrates significantly higher than the original design and upgrading service factors of 100.0 per cent. Service factors this high would only be achieved in years that do not require scheduled maintenance shutdowns. Syncrude expected that typical years would see service factors in the 95.0 per cent range which would be sufficient to sustain SCO production near the 12.0×10^6 m^3/yr level. Syncrude felt that recent plant performance demonstrated it's potential to achieve this operational reliability on a sustained basis.

2.1.2 Expansion Project Design and Construction Start Date

In 1988, Syncrude received Board approval for an expansion project that would increase SCO production by 5.0×10^6 m^3/yr beyond the approved limit of 10.0×10^6 m^3/yr. The approval was conditional on the construction for the project commencing by 31 December 1992. The expansion project design was based on:

- truck and shovel mining and warm slurry extraction for incremental bitumen production, and
- expanded catalyst bed hydrocracking for the incremental bitumen conversion (primary upgrading) capacity.

In its current application, Syncrude proposed to modify its original design to include the hydraulic transport (hydrotransport) of oil sand which it believed was an improvement over the original design. No other significant design changes to the 1988 proposal were contemplated. Syncrude stated that it believed no other commercially proven or emerging technologies were presently available that would justify, from either an energy efficiency or environmental perspective, any further changes to the previously approved technologies.

The original expansion project approval was based on a maximum level of SCO production after expansion of 15.0×10^6 m^3/yr. Syncrude requested that the approved SCO production limit now be amended to specify 17.6×10^6 m^3/yr to reflect the full capability of the expansion project when added to the requested new limit of 12.6×10^6 m^3/yr for the existing facilities. Syncrude acknowledged that the specific capacity of the expansion project was being revisited and could ultimately be anywhere from 14.5 to a maximum of 17.6×10^6 m^3/yr.

Syncrude also applied for a 5-year extension (to 31 December 1997) to the date by which construction of the expansion project must proceed. It argued that the business climate to this point in time had not favoured proceeding with a major expansion and current conditions continued to remain unfavourable. The fact that the technology chosen for the expansion project remained current was offered as justification to support an extension of the approval lapse date. Syncrude also noted that if significant technology developments were to take place which might serve to alter the project design choices, it was within the Board's power to reopen the approval.

2.1.3 Bitumen Supply

Syncrude's bitumen production forecasts contained in the application were based on a 12.0×10^6 m^3/yr level of SCO production with an expansion to 15.0×10^6 m^3/yr in 1998. To achieve this higher level of production over the requested project duration would require additional oil sands mining areas beyond those described by Syncrude in previous applications to the Board. Syncrude was therefore seeking approval for additional mining areas within the approved project boundary (Figure 1). Bitumen supply profiles in the application also identified some bitumen from sources other than the current Syncrude mine. Syncrude did not, however, request approval for specific off-lease sources at this time. Rather, Syncrude indicated it intended to make separate application for such sources if and when they were required. Syncrude acknowledged that SCO production rates above 15.0×10^6 m^3/yr could not be sustained from bitumen found within the existing lease boundaries. It proposed to import bitumen or apply to develop other mining areas if production levels above 15.0×10^6 m^3/yr were to be found attractive.

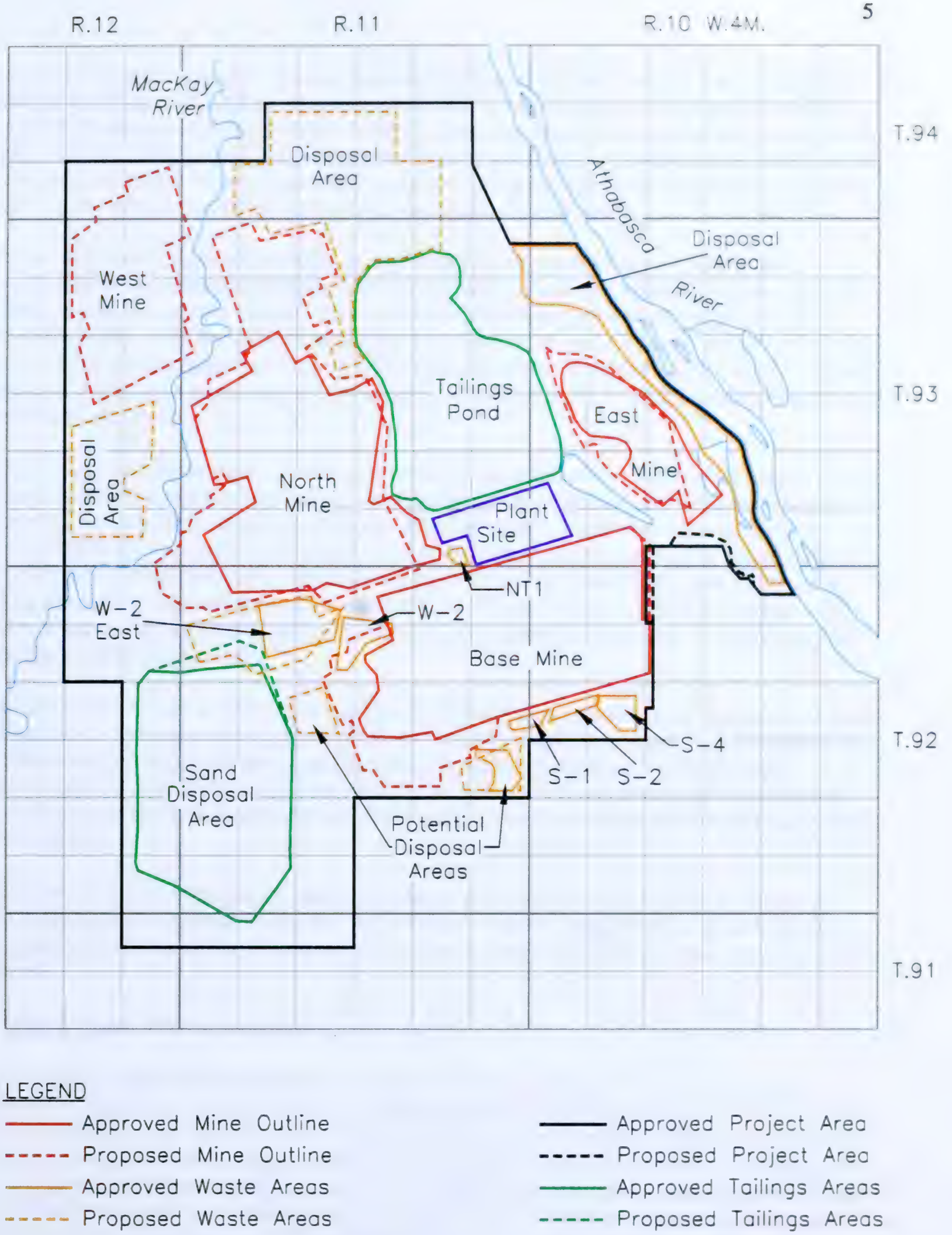


FIGURE 1: SYNCRUDE OIL SANDS PROJECT
MILDRED LAKE AREA

Syncrude requested that approval be granted to allow it to import bitumen from off-lease sources for processing in its upgrading facilities. It also requested that it be given approval to export bitumen produced from its leases to other processing facilities. Both operations had occurred on a limited basis in the past, but required approval by the Board on a case by case basis. If its application were granted, Syncrude advised that such future transactions would not require individual approval but would instead be detailed on the current monthly production reports submitted to the Board.

Syncrude noted that the requested flexibility to import and export crude bitumen would in effect decouple the bitumen production operations from the upgrading operation. Syncrude believed that this would better utilize the capacity of each, and would assist in increasing the output of SCO from the Mildred Lake facility. The flexibility to import bitumen from other sources would also allow Syncrude to reduce its reliance on a single ore body of declining productivity. It argued that this would improve the viability of a long term processing operation and provide justification for ongoing modernization and improvements to the facility.

Syncrude also argued that the future development of the oil sands industry would likely be based on the development of bitumen supplies remote from an upgrader as it believed financial hurdles associated with new supplies could be reduced by utilizing an existing facility. Approving imports was also considered positive for the future development of the industry as it had the potential to create short term bitumen markets for other producers. Syncrude believed the Mildred Lake facility could ultimately evolve to a stand-alone upgrader, but not for perhaps some 50 years or more. Such a direction in its approval was seen as no more than putting the Mildred Lake upgrader on the same level playing field with upgraders outside the province.

Syncrude acknowledged that an increase in truck traffic through the city could occur as a result of some import operations. Syncrude advised, however, that it had joined with Suncor and Fort McMurray to form a committee to work on the development of a disaster services emergency response plan. Syncrude intended to continue its involvement in this area and stated it was committed to consulting with Fort McMurray and with Alberta Transportation officials on future plans which could impact area roads and highways.

Syncrude believed that bitumen imports and exports to the plant should not be restricted. It saw no reason to constrain such activities as any new major bitumen supplier would require its own approvals and consequently would be subject to a regulatory process whereby any public or other concerns could be addressed.

2.1.4 Project Approval Term Extension

Syncrude argued that extending the project expiry date to 2025 would improve the overall project economics and facilitate long term planning. It maintained the increased project life of 7 years would provide for increases in reserves and hence increased asset value for the project. This, in turn, would help build investor confidence for future investments in either the staged development or the expansion project. Syncrude argued the longer life would also provide for a reasonable economic return on such investments thus increasing the probability that they would occur. Syncrude noted that if expansion construction were to start as late as 1997, the requested 7-year extension of the approval would provide only 25 years of return on investment. This was considered by Syncrude to be the minimum desirable for such a project.

Syncrude argued that the requested approval term was not unlike the terms that would be considered for new, grassroots investments. It also noted that the term requested was similar to that granted in 1988 when the expansion project was first approved. It believed the longer term would extend the business and environmental planning horizon in a manner consistent with sound conservation and environmental protection practices.

2.2 Environmental Issues

2.2.1 Atmospheric Emissions

Actual and Predicted Emissions

Syncrude provided estimates of the mass of atmospheric emissions resulting from its Mildred Lake operations. The specific emissions that were identified and addressed in the application include sulphur dioxide (SO_2), carbon dioxide (CO_2), oxides of nitrogen (NO_x), hydrogen sulphide (H_2S), particulates (including heavy metals), and hydrocarbons including volatile organic compounds (VOCs).

Table 2 summarizes Syncrude's evidence regarding the actual and predicted emissions from its facility for some of the major pollutants that are released on a continuous basis from the main stack.

TABLE 2: ACTUAL AND PREDICTED EMISSIONS (tonnes per day)

	SO_2	CO_2	NO_x	Particulates
Historical data 1986-1991	206.0	16 725	28.4	9.79
10.0×10^6 m^3/yr (design)	258.2	20 313	39.4	11.81
12.6×10^6 m^3/yr	260.0	23 466	45.5	13.92
15.0×10^6 m^3/yr*	222.0	29 140	51.4	2.57
17.6×10^6 m^3/yr	<258.0	33 045	53.5	<13.92

* Based on the operations and facilities described in the 1987 expansion application.

Syncrude also acknowledged that indirect emissions from on-site and off-site generation of electricity used for its project would add in the order of 640 tonnes of CO_2 per day (t/d) for the 10.0×10^6 m^3/yr design case and 778 t/d for the 12.6×10^6 m^3/yr case. Syncrude believed that its increased emissions would not have a regional impact but acknowledged it would cumulatively contribute to global CO_2 emissions.

Particulate emissions from the Syncrude facility include wind borne dust from the plant and mine areas as well as fine particulates from the main stack that are not removed by the electrostatic precipitator (ESP). Syncrude believed that the particulates from the main stack are generally of greater environmental concern as the heavy metal content can be enriched during the combustion process.

Syncrude provided evidence on fugitive emissions as well. A 1987 survey found total emissions of 507.0 grams per second (g/s) volatile hydrocarbons and total reduced sulphur (TRS) emissions of 2.01 g/s. The majority of both types of emissions were found to originate from the tailings ponds. A follow-up survey conducted in 1992 found that the volatile hydrocarbon emissions and TRS were lower than 1987 levels by 15.0 per cent and 50.0 per cent respectively.

Ozone (O_3) was another pollutant of interest, although it is not directly emitted by the Syncrude facility. Although Syncrude acknowledged that while ozone levels in the region were relatively high at times, it was uncertain as to whether the levels were attributable to natural sources or to regional interactions between hydrocarbons (both anthropogenic and natural sources) and NO_x emissions.

Syncrude acknowledged that cumulative emissions would increase as a result of its staged development proposal and extended project life. The proposed extended plant life at current emission rates would result in a 0.5 million tonne (Mt) increase in cumulative SO_2 emissions in the region. An increase in Syncrude's average production to 12.0×10^6 m^3/yr would add an additional 0.7 Mt to predicted cumulative emissions. Combined, this would represent an increase of 41.0 per cent over an extrapolation of actual historical emissions and a 20.0 per cent increase over the predicted (or design estimates) emissions for the approved 10.0×10^6 m^3/yr case. Syncrude believed that this represented a worst case scenario and noted that, should the expansion project proceed, main stack emissions would be reduced thereby reducing overall cumulative emissions.

Flaring and Diverting

Syncrude acknowledged that the diverter stacks and flare stacks emit SO_2, H_2S, particulates, and other emissions on an intermittent basis and can contribute significant volumes during individual flaring and diverting events. Current use of the diverter stacks appears to occasionally result in off-site odours and exceedances of ambient air quality objectives, but Syncrude argued that this would not become any worse with its staged development proposal.

Licence Limits

Syncrude's current AEP licence specifies hourly, daily and 90-day-rolling-average SO_2 emission limits of 16.4 t/h, 292 t/d, and 260 t/d respectively for the main stack. The current ERCB approval specifies a 265 t/d 90-day-rolling-average emission limit for SO_2 from all plant sources, including the diverter, flares, and fugitive sources. Syncrude believed that the proposed increase in SCO production to 12.6×10^6 m^3/yr could be achieved within these existing limits. Although its absolute SO_2 emissions would increase from current levels, Syncrude argued its 'per unit of production' SO_2 emission rates would be lower. Should the expansion project proceed, it was expected to result in reduced emissions on both an absolute and per unit of production basis.

Syncrude's main stack licence limits for NO_x (expressed as NO_2) and particulates are 2.15 t/h and 0.6 t/h respectively. Syncrude believed that its proposed production rates would result in increased NO_x emissions, but was satisfied its current operating licence limits would not be exceeded.

Federal Initiatives

Syncrude recognized that an understanding of atmospheric emission levels were important to provincial and federal government organizations who are involved with preparing and updating inventories and developing national and international policy. It acknowledged that, while it is very clear that Canada as a nation had developed a NO_x and VOC management plan which identified the areas in which emission reductions would be most beneficial, it was not aware of any specific documents or programs that would require individual regions of the country, an individual industry, or individual companies to reduce emissions or hold emissions to some previous level. Syncrude took the same position with regard to the federal agreements to stabilize Canadian greenhouse gas (primarily CO_2) emissions.

In the case of the SO_2 emissions reduction, Syncrude acknowledged Canada's international commitments under the Helsinki accord. It noted, however, that Canada's official negotiating position called for the application of best available technology in the case of new facilities, but specifically argued against the retrofit of such technology to existing facilities on the grounds that there was no environmental justification in Canada for such measures.

Emissions Reduction

Syncrude outlined a number of measures by which reductions in its emissions would take place.

Syncrude believed that an emphasis on prudent operations and continuous improvement techniques would result in lower overall SO_2 emissions from its facility than were predicted in its application. It planned to use this approach to improve the recovery efficiency of its sulphur plant and to decrease the average flare and diverter SO_2 emissions below the 5 t/d level. Other proposed initiatives that would be expected to result in reduced SO_2 emissions included the reduction of coke fines carry-over from the cokers and improved hydrocracker desulphurization. Syncrude indicated that if its approach and initiatives were not successful in reducing SO_2 emissions, it would either find a capital solution or would limit SCO production levels to stay within its licensed emission limits.

Syncrude noted it had considered a number of major (i.e. capital intensive) initiatives to reduce SO_2 emissions including upgrading technology changes and flue gas desulphurization (FGD). It acknowledged that if it were proposing a new grass-roots facility, it would be possible to achieve the proposed SCO production volumes with significantly lower levels of emissions. However, it argued that in the absence of compelling environmental justification, such options were not warranted due to their high operating and capital costs and lower energy efficiency. In the case of a CH_2M Hill Engineering Ltd. report tabled by SEAC, Syncrude also disputed the estimated capital cost for retrofitting the CANSOLV FGD process which it argued would be closer to $200.0 million per boiler rather than $104.0 million.

With regard to VOC emissions, Syncrude indicated that it intended to pursue modifications to its naphtha recovery unit (NRU) which it anticipated would increase naphtha recoveries to a level of 80.0 per cent or greater. This it argued would significantly reduce VOC emissions from its tailings pond.

Syncrude identified two approaches it would take to reduce NO_x emissions. The first involved reducing the volume of fuels consumed through an energy conservation program. The second involved the installation of low NO_x burners on boilers and large furnaces. Syncrude noted that it had and would continue to take advantage of appropriate opportunities to install these burners but, because it believed that regional levels of NO_x emissions were not a problem, further burner replacements on purely environmental grounds were not considered justifiable at this time.

CO_2 emission levels are also related to energy utilization and therefore Syncrude proposed to utilize energy efficiency initiatives to reduce its CO_2 emissions. CO_2 recovery was also considered as an alternative means of achieving reductions, however, Syncrude felt that the economics of this option were poor as there was no demand for CO_2 in the region and the cost to pipeline to potential oilfield users would be prohibitive.

Syncrude outlined a number of specific initiatives currently underway or completed that would reduce particulate emissions from the main stack. These included reductions in coke fines carry-over to the boilers, improved solids withdrawal from the ESP's, reduced coker burner cyclone fouling and improved boiler combustion control. If these initiatives proved unsuccessful, Syncrude indicated that it would consider routing the sulphur plant tail gas stream to a separate incinerator or adding additional ESP transformer capacity.

Sulphur Deposition

Syncrude provided estimates of the wet and dry deposition of sulphur compounds in the region, based on AEP's ADEPT2 dispersion model using three meteorological data sets and actual and predicted emissions from Syncrude's main stack and Suncor's powerhouse and incinerator stacks (**Table 3**). Wet deposition was expressed in terms of acidifying potential (AP) as suggested by the Interim Acid Deposition Loading Task Group and dry deposition was expressed as effective acidity (EA) as defined by AEP.

TABLE 3: SYNCRUDE WET AND DRY DEPOSITION PREDICTIONS[1]

		Effective Acidity ($kmol\ H^+/ha/yr$)	**Acidifying Potential ($kmol\ H^+/ha/yr$)**
1991 SO_2 Emissions	Syncrude main stack	0.11	0.12
	Syncrude and Suncor[2]	0.33	0.51
$10.0 \times 10^6\ m^3/yr$	Syncrude main stack	0.14	0.15
	Syncrude and Suncor	0.35	0.51
$12.6 \times 10^6\ m^3/yr$	Syncrude main stack	0.15	0.16
	Syncrude and Suncor	0.35	0.51
$15.0 \times 10^6\ m^3/yr$	Syncrude main stack	0.12	0.13
	Syncrude and Suncor	0.34	0.51

[1] Values are based on the ADEPT2 model and the OSLO meterological data set.
[2] Includes Syncrude's main stack and Suncor's powerhouse and incinerator stacks.

The Acid Deposition Loading Task Group has identified an AP interim critical range of 0.12 to 0.31 kmol $H^+/ha/yr$ to protect highly sensitive ecosystems. AEP has identified three sensitivity classes and EA target loading criteria for soils and aquatic systems as outlined in **Table 4**.

TABLE 4: EFFECTIVE ACIDITY DEPOSITION LIMITS ($kmol\ H^+/ha/yr$)

	Soils	**Aquatic Systems**
Low Sensitivity	0.70 to 1.00	> 0.30
Medium Sensitivity	0.30 to 0.70	> 0.30
High Sensitivity	0.10 to 0.30	0.10 to 0.30

Syncrude noted that the AP critical ranges and the EA target loadings were interim and that there were currently no objectives for rates of deposition in Alberta. Its rationale for comparing its predicted values with these suggested limits was to assist and encourage AEP to continue to review and finalize these limits. Syncrude believed that it was premature to use them as a basis for regulatory decisions concerning its application.

Syncrude defended its use of AEP's ADEPT2 computer model for estimating the wet and dry deposition of sulphur compounds associated with emissions from the oil sands facilities in the region. It was argued that, although other computer models were available, the ADEPT2 model was considered suitable for the Syncrude predictions as its results were generally consistent with those reported by others who had used different models to develop regional estimates. While it was acknowledged that the performance of the ADEPT2 model as a whole had not been evaluated (i.e. predictions compared to actual observation), it was noted that the sub-models that comprise ADEPT2 were derived from field-tested relationships reviewed in the scientific literature.

Syncrude questioned the basis of the EFONES estimate of total sulphur deposition (i.e. from 1978 throughfall and stemflow data previously published by Nyborg and unpublished field notes) and argued that the technique had no support as a method for estimating total sulphur deposition in the oil sands region. It concluded that because the data did not show a consistent relationship between the distance from the emission source and the level of sulphur deposition, the data were suspect. Syncrude also disputed EFONES claim that regional soil sulphur and pH measurements conducted by Nyborg in the fall of 1993 supported sulphur deposition rates derived from Nyborg's 1978 throughfall data. It argued that EFONES conclusions were based on a selective use of the 1993 data. Syncrude concluded these data showed a lack of consistency between total soil sulphur load and pH changes and exhibited no consistent pattern of pH change.

Vegetative Effects

Syncrude argued that regional monitoring had not produced any evidence of soil acidification that could be attributed to sulphur deposition. It based this conclusion on a review and assessment of all acidification research for the region that had been done over the past 20 years including soil pH evidence submitted following EFONES October 1993 soil sampling program conducted in the Fort McMurray region. Syncrude interpreted this latter EFONES evidence to show that only one of the seven sites examined had exhibited a substantial and statistically significant reduction in soil pH. It argued that given potential problems with the method of pH determination used by EFONES and recognizing the seasonal, annual and natural variations in pH, no conclusions could be drawn from the data regarding the impact of acidic deposition on soils in the area. Syncrude noted, however, that it was committed to a thorough, ongoing tracking of soil chemistry in the region and recognized the Board's authority to respond to any new information which could possibly come forward in the future.

Syncrude argued that the references culled from other studies and guidelines by SEAC to demonstrate vegetative damage were taken out of context and if properly considered would not support SEAC's position. It cited SEAC's evidence with regard to infrared photography as a specific example and noted that, even if a linkage between the infrared indications of vegetation stress and the Syncrude main stack was assumed, there was no evidence that the areal extent of vegetation stress had grown significantly in the last decade. Syncrude argued that, in fact, the evidence indicated that between 1984 and 1991, the areal extent grew by only 300 hectares which was equivalent to about 1.5 per cent of the treed area that would be removed by Syncrude under its proposed development plan.

Syncrude acknowledged that localized vegetation stress, concentrated in the Athabasca River valley, had been detected but it argued that the stress was not caused by emissions from the Syncrude main stack. It also argued that, to the extent that vegetation stress occurred, it was temporary and reversible. Syncrude therefore believed that the appropriate response, if any, would be to reduce emissions from low level sources located within the valley which, by definition, would not include the Syncrude main stack.

Ambient Air Quality

Syncrude acknowledged that the ambient SO_2 concentrations in the region could be expected to increase marginally as a result of its proposals to increase production. It suggested that if the Mildred Lake facility were operating in isolation, the proposed emission levels would result in no exceedances of AEP's ambient air quality annual or daily objectives and only a few exceedances of the hourly objective. It conceded that, when its emissions were combined with Suncor's current levels, higher ambient concentrations would occur. Syncrude argued that, from a regional perspective, the magnitude of the predicted ambient concentrations would continue to be similar to historical levels. It further argued that its predicted frequency of exceedances was likely an overestimate.

Syncrude stated that because of the relatively small amount and wide distribution of NO_x emissions, likely ambient concentrations of NO_x were not as well defined as was the case with SO_2 emissions. None the less, maximum predicted hourly concentrations were not expected to exceed Alberta's air quality objectives even though ambient concentrations of NO_x were expected to increase due to the increased production.

In general, Syncrude felt that the region was exceptionally well supplied with air quality monitoring equipment and noted that the existing air quality monitoring system had been subject to past reviews by the Regional Air Quality Coordinating Committee (RAQCC). It argued that this had resulted in several enhancements to the system in each of the last 3 years. Syncrude emphasized its view that system optimization would be a more appropriate response to regional air quality monitoring concerns than would a substantial expansion of the monitoring network. Syncrude stated that it is committed to future participation and support of either RAQCC or a zonal air monitoring management system as proposed by the Clean Air Strategy for Alberta (CASA).

Health Impacts

Syncrude commissioned a study which attempted to evaluate the potential health risks to people living in Fort McKay and Fort McMurray as a result of exposure to only atmospheric emissions from the Syncrude facility (i.e. excluding other sources, including Suncor emissions). The study considered potential risks from both long and short term exposures based on predicted average and 1-hour maximum emission levels. In both cases the study attempted to determine whether the predicted level of exposure would exceed a level believed to produce a measurable health effect (the exposure limit). The study found that none of the predicted long term exposures resulting from the Syncrude emissions alone were greater than the accepted exposure limits. In fact, with the exception of the oxides of nitrogen and sulphur, exposures from Syncrude's emissions alone were generally less than background levels (i.e. those associated with a relatively pristine environment). In the case of short term exposures, none of the substances considered were found to be a concern. The predicted short term SO_2 exposures did exceed the World Health Organization guidelines, however, based on the conservative nature of these guidelines, the levels were not expected to produce any pronounced adverse human health effects.

Syncrude argued there was little substantive evidence that the incremental emissions associated with its application would have any discernible health impact. It therefore concluded that there was little cause for concern regarding the potential regional health impacts from oil sands activities. However, Syncrude recognized concerns in the region about possible impacts from atmospheric emissions and was therefore willing to strongly support a regional health study that would include regional stakeholders. It noted that it was prepared to contribute a fair share of the costs as well as act as a catalyst to initiate the study.

2.2.2 Reclamation

Need for Approval and Jurisdiction

Syncrude's application requested approval by the ERCB of its lease development and reclamation plans with specific reference to plans for fine tails reclamation. The plans outlined in the application provided a conceptual level of detail for the interrelated mining activities which include site dewatering, tree clearing, muskeg and overburden removal/storage, oil sand mining, tailings disposal, and reclamation. Syncrude argued that reclamation was a fundamental and ongoing activity in its mining operation and any development plan required the inclusion of a reclamation component. Since reclamation was being carried out while the mine was active, Syncrude suggested that Board approval of all aspects of the mining operation was necessary to provide a sound basis for ongoing lease planning. Approval of the conceptual reclamation plans were also sought in order that Syncrude could confidently embark on its long term obligations in this area, with a benchmark from which it could measure improvements in reclamation practices achieved through ongoing research and development work.

Syncrude argued the Oil Sands Conservation Act provided the Board with clear jurisdiction to deal with reclamation matters in the context of an oil sands mining operation.

Overall Site Reclamation

Syncrude stated that its reclamation objective was to create a diverse ecosystem which was biologically self-sustaining, geotechnically stable and non-erosive, maintenance-free, and with a productive capability at or above pre-disturbance levels. To accomplish this objective, Syncrude proposed a final reclaimed landscape that was comprised of 50.0 per cent forest, 20.0 per cent grasslands, 20.0 percent water capped fine tails or lakes and 10.0 per cent wet lands. Syncrude maintained the proposed final landscape was in part a result of public consultation and argued this distribution of features satisfied its reclamation objective. It noted, however, its plans were still flexible to allow stakeholder input and to accommodate necessary change.

Syncrude stated it had made and would continue to make a significant commitment to research and development to support its overall reclamation plan and noted its past research efforts had covered all aspects of reclamation including fine tails, soils, vegetation, wildlife, water quality, and aquatic resources. It argued its future research and development expenditures of $23.0 million also represented a balanced program which would support an integrated approach to wet and dry landscape features, although the primarily focus would be on the development and design of the base mine lake and wetlands, computer modelling, and fine tails management techniques (as described in the following sections).

Syncrude noted that much of its past dry land reclamation research and development efforts had been conducted in the field under the actual conditions that would be intended to support the various types of vegetation being investigated. This it argued would provide the opportunity for reclamation procedures to be modified and enhanced to ensure a success. Syncrude conceded that not all of its reclamation research projects had been totally successful and future projects could also suffer setbacks, but Syncrude was committed to ultimately achieving the goals of its reclamation research. Syncrude stated that every effort would be made to ensure success and noted that substantial incentive to be successful existed in the form of regulatory supervision, contractual obligations as the lessee of lands from the Crown, financial security posted to ensure performance as well as Syncrude's own internal policies and procedures. Syncrude argued that the weight of the evidence supported Syncrude's willingness and ability to pursue reclamation of its site in accordance with its obligation and commitments.

Fine Tails Reclamation

Fine tails is a gel-like mixture of clays, minerals, bitumen, and water formed as a by-product of the hot water bitumen extraction process used by Syncrude in its Mildred Lake plant. The nature of the material is such that it will not readily settle or consolidate. In fact, consolidation to 40.0 per cent solids occurs only after many years of undisturbed settling. Consequently large storage areas are required to contain the large volumes of fine tails that accumulate until such time as they can be reclaimed. The aqueous fraction of fine tails, often referred to as pore water, has been found to exhibit acute toxicity (i.e. to be lethal to fish over periods of 96 hours). This toxicity has primarily been attributed to the presence of various organic compounds, particularly naphthenic acids.

Syncrude noted that since 1989 it had spent approximately $13.0 million on research projects to investigate fine tails reclamation and management methods. These included the investigation of the fundamental properties of fine tails, the sources of their toxicity, techniques for the management of fine tails (see Section 2.2.3), as well as various reclamation concepts. A computer model for simulating conditions and interactions between various features of a reclaimed landscape had also been developed to help identify parameters that could be used to monitor the success of reclamation efforts. During the earlier years of the project, restoration of the fine tails to a solid or dry landscape was recognized as a more desirable and likely reclamation scenario. The more recent research, however, has suggested that techniques that reclaim the fine tails in there natural state offer an attractive alternative.

Syncrude argued that, based on its research and development work, it was satisfied that it could reclaim its accumulated volume of fine tails in an environmentally acceptable manner. It also concluded, however, that there was no single approach available to manage the fine tails volumes that was technically, environmentally, and economically acceptable. Syncrude believed that the optimal approach integrated volume management techniques (described later in Section 2.2.3) with water capping of fine tails (water-capped fine tails) as the preferred reclamation approach.

To carry out the water-capped technique, mature fine tails would be placed into the mined out pit. A layer of capping water would then be placed on top of the fine tails to form a fresh water lake. The capping layer would be of sufficient depth to prevent mixing of the fine tails and water. At the interface between the fine tails and capping water a detrital layer is expected to form which would also serve to prevent resuspension of the fine tails and would act as the primary zone for bacterial decay of the naphthenic acids and other organics released from the fine tails. The metabolism of these organics by bacteria would in turn reduce the toxicity of the pore water to aquatic organisms. After allowing sufficient time to ensure the capping layer was non-toxic (estimated to be 5 to 10 years), local surface run-off would be introduced to the lake with a discharge established to complete the connection to the local site drainage system.

The water-capped fine tails concept was the focus of considerable attention in Syncrude's reclamation research and development program. A major component of this program included the development of a series of seven test pits each containing approximately 1000 m^3 of fine tails. These pits were used to investigate a number of parameters critical to the demonstration of the long term environmental feasibility of the reclamation strategy including: geotechnical stability, hydrogeology, toxicity, and biodegradation.

In proposing the water-capped fine tails concept, Syncrude acknowledged that not all the required detailed engineering had yet been completed and that additional investigations and analyses were needed in several areas. One such area was the geotechnical stability of beaches and containment dykes, however, Syncrude argued that it had a world class engineering design team and review panel which could address any outstanding design issues.

Syncrude also acknowledged that further investigation of the possible impact the fine tails could have on the surrounding hydrogeology was required, along with additional ground water monitoring. However it argued that, based on the results of modelling and observed performance to date, the risk of ground water and aquifer contamination was very low, particularly since the fine tails would be placed back in-pit where they would settle (and consolidate) to form a relatively impermeable barrier against the slopes and bottom of the pit and be further contained by in situ oil sands which also have a very low permeability.

Syncrude conceded that the toxicity of the pore water associated with fine tails was a subject of considerable debate and concern among stakeholders. Based on a number of research projects, Syncrude had confirmed that freshly produced fine tails and fine tails pore waters were acutely toxic to aquatic organisms. However, its research had also indicated that fine tails, isolated from the input of fresh tails and maintained under aerobic conditions, would detoxify within 6 to 12 months as a result of a range of physical, chemical and biological processes. Syncrude also acknowledged that concerns prevailed over the quality of water ultimately discharged from the fine tails lakes. In recognition of this, Syncrude described the possibility of using wetlands to provide additional treatment of this discharge. In support of this concept it had developed a research program which included the examination of the various physical, chemical and biological processes occurring within wetlands used to treat waste waters. Syncrude was confident that wetlands could provide a self-sustaining waste treatment system which would allow discharge of water off lease. The primary processes included incorporation of materials not readily metabolized into the sediments as well as enhanced aerobic and anaerobic degradation of various organics and other nutrients.

Although Syncrude concluded that any outstanding issues surrounding the water-capped fine tails concept were relatively minor and could be addressed during the design phase, it proposed the development of a larger scale test to confirm its previous research and development findings from the seven test pits. In 1993, Syncrude initiated this test by completing the construction of a 200,000 m^3 test pond into which 120,000 m^3 of fine tails was transferred. The results of this test would not be available for some time.

Several stakeholders had questioned whether the 200,000 m^3 test pond would be large enough to provide the necessary information to implement the reclamation concept at full scale. In response Syncrude proposed a full scale test, known as the base mine lake concept to confirm the feasibility of the water-capped fine tails reclamation proposal. The proposed lake would contain approximately 150.0×10^6 m^3 of fine tails with a 5 metre capping layer of fresh water. Initially no discharge from this lake would be permitted. Once toxicity levels in the water cap had declined to acceptable levels, local water would be diverted into the lake and a discharge into Beaver Creek established. Discharge from the lake would ultimately be contingent on obtaining appropriate regulatory approvals and would be subject to demonstrating that the discharge had no negative environmental effects and met acceptable water quality standards.

Syncrude agreed to involve all stakeholders in the design of the monitoring program and performance standards for the base mine lake. If the base mine lake did not successfully demonstrate the proposed reclamation approach, Syncrude agreed to develop further alternatives in consultation with its stakeholders and to make any necessary changes to effectively reclaim the lake.

In response to questions from the Board staff, Syncrude provided evidence on the various technologies available that might be considered for use to recover a portion of the residual bitumen contained in fine tails prior to any reclamation activities. It was Syncrude's view that none of the currently available technologies had been shown to be effective, economic and compatible with its reclamation objectives. Syncrude also noted that it believed there was no observable beneficial effect on reclamation that could be gained by reducing the amount of residual bitumen in its fine tails. It also concluded that there were many other more cost-effective sources of bitumen available to it and it therefore did not propose any additional work in this area.

2.2.3 Fine Tails Management Alternatives

Syncrude argued the environmental significance of Syncrude's fine tails was primarily a result of the large volume rather than any associated toxicity, which Syncrude believed to be relatively short-lived. In Syncrude's view, the main environmental impact associated with the fine tails volume was the additional land disturbance which resulted from disposing of coarse sand tails outside of the mine pit in order to retain adequate space for fine tails in-pit. Recognizing this, Syncrude proposed to continue to develop fine tails volume reduction initiatives which were economic.

One such initiative, which Syncrude considered proven and cost effective, was proposed in the current application. The technique, known as "engineered tails", increases the concentration of fines in the sand tails deposits by increasing the density of the whole tailings stream and "spiking" it with fine tails. Syncrude was committed to implementing this initiative in 1996 and was targeting for a reduction in the annual volume of liquid fine tails by as much as 20.0 per cent. This was viewed as a proactive measure and Syncrude intended to continue research and development work to further optimize the technique to improve the rate of fine tails capture.

Syncrude indicated it was also developing a variety of techniques for mixing fine tails together with overburden. A mixing technique known as poldering had been demonstrated in a large scale field test and was considered technically feasible. Theoretically, poldering could dispose of the majority of the fine tails produced, however it was estimated to cost up to twice that of engineered tails and was therefore not considered cost effective at this time. Syncrude was, however, continuing research into other methods for mixing fine tails with overburden. One such method, the hydraulic transport of overburden with fine tails, showed promise but considerably more work was required in order to demonstrate its technical feasibility.

Another technique that Syncrude believed showed promise in reducing the volume of fine tails involved the chemical treatment of the whole tailings to produce a non-segregating slurry. A number of laboratory and field scale tests had recently been conducted which involved the addition of lime, acid and combinations of the two. Syncrude noted that this technique has the potential to significantly reduce the volume of fine tails produced, however, more work was again required to demonstrate both the cost effectiveness and technical viability of the approach.

Syncrude advised that some limited research had also been conducted to investigate the utilization of freeze-thaw cycles to increase the solids content of fine tails. It noted the results were encouraging but believed that considerable more research on issues of water chemistry and commercial application logistics were necessary before the technique could be proven technically feasible.

Syncrude had also considered opportunities to reduce the volume of fine tails produced by altering the extraction process. The hydraulic transport/warm slurry process (which is the basis for the expansion project) was considered by Syncrude to be its best option in this regard as the process complemented the previously described engineered tails initiative by reducing the amount of water entering the system. In general terms however, Syncrude did not believe that a demonstrated extraction process existed that could significantly reduce the volume of fine tails produced. Syncrude noted that many extraction technology developers claimed that their process offers reduced volumes of fine tails, but to date it had found little evidence to support such claims. In the case of some processes developed by OSLO, Syncrude acknowledged that claims of improved tailings characteristics were supported by some limited testing. To more fully investigate this Syncrude planned controlled tests at its research facility to do a side by side comparison of the performance of the OSLO and Clark hot water processes.

It had been suggested that fine tails volumes might also be controlled by selectively mining ores with properties known to result in lower levels of fine tails production. While Syncrude acknowledged there may be some opportunity in such an approach, it noted the relationship between fine tails volume and ore characteristics are very complex and not sufficiently well understood at this time to assess the viability of this approach. It noted that bypassing ore for the reason of fines content would also impact the size of the mine and hence the area disturbed. This it argued had clear economic, environmental, and other implications for the operation.

In summary, Syncrude argued that, given the current state of development of fine tails management techniques, the proposals included in its application (i.e. engineered tails and water-capped fine tails – Section 2.2.2) represented the best balance between the technical, environmental and economic components of this issue. Syncrude indicated it was committed to continuing research in this area and, to the extent that future developments were technically and economically viable, would consider incorporating new approaches at the Mildred Lake facility.

2.3 Socio-economic Issues

Syncrude advised that its aboriginal socio-economic program had existed since the beginning of its Mildred Lake operations. It noted that over the years its commitment to such a program had been reaffirmed and argued that the program had improved with increased experience. It explained that its current aboriginal program was based on a loose integration of three components: community development; business development; and training, education, and employment.

Syncrude noted that its community development objectives were based on providing assistance, when requested, to aid a community in meeting needs consistent with a long term goal of the community becoming self-reliant. Since 1983, Syncrude had provided over $1.3 million in funding to six local aboriginal communities for a wide variety of community development initiatives.

Syncrude noted that it had also been engaged in business development activities with aboriginal businesses and individuals since before its operations began. Since 1984 it had done more than $98.0 million in business with aboriginal companies. In 1993 approximately $20.0 million of Syncrude's $150.0 million contract budget went to these companies. Syncrude was targeting for this value to reach $30.0 million by 1997. Its commitment to aboriginal businesses has been achieved through both sole-sourcing contracts and on occasion restricting bids to only aboriginal contractors. While Syncrude expected these practises to continue for some years to come, ultimately it expected aboriginal businesses to become sufficiently self-reliant to be able to compete for contracts in the open marketplace.

Syncrude stated that it placed a strong emphasis on training and education for the effective operation of its business and noted that as of 1990 all new employees required Grade 12 or a General Equivalency Diploma (GED). Syncrude explained that some exceptions are made in the case of aboriginals, however, there is still the expectation that they acquire a GED within 2 years of employment. It was also noted that the children of all employees are eligible for post secondary education grants provided they achieve certain levels of academic performance and Syncrude has two scholarship awards available exclusively to aboriginal students.

Syncrude reported that it currently directly employs 284 aboriginals which was an increase of 59 over the last 5 years. It noted also that the turnover rate for aboriginal workers had decreased from a high of 160.0 per cent in 1980 to a current level that is comparable or less than that for its entire workforce. Syncrude targeted to achieve, by 1997, a level of aboriginal employment in its direct workforce that was representative of the proportion of aboriginals in the local region. Syncrude suggested this would amount to about 10.0 per cent of its workforce or about 400 employees. It noted that as it continued to pursue a process of down-sizing and rationalizing its labour requirements, achieving this goal would not be straight forward and may require extraordinary measures. As an example, in 1992 Syncrude implemented a hiring policy that, in effect, required all entry level positions to be filled by aboriginals. In 1993, all 24 such positions were filled consistent with this policy.

Syncrude stated that it also directly encourages its contractors to employ aboriginal workers or subcontract work to aboriginal businesses. It noted that this is monitored through its Native Development Steering Committee and through terms in all contractor agreements which require the disclosure of the aboriginal content of the contract. Currently 296 aboriginals are employed by contractors working for Syncrude.

Syncrude indicated that much of its commitment and effort regarding aboriginal socio-economic issues would be directed through the Athabasca Native Development Corporation (ANDC), an association of the First Nations and Metis Locals in the region. It explained that the basis of its dealings with ANDC were the subject of a draft 5-year accord, the latest in a series of accords dating back to 1977. The accord outlined Syncrude's commitments to aboriginal business development and employment and reflected many of the initiatives described above. Under the terms of the agreement, Syncrude would not provide funding for the ANDC administrative services required to fulfil the articles of the accord although it would support the ANDC in its efforts to have the provincial and federal governments provide the appropriate funding.

Syncrude acknowledged but disagreed with criticisms by the ATC and Fort McKay with regard to the lack of achievements resulting from previous ANDC accords. It believed progress had been made (as described earlier) and reminded that none of the parties had a problem with the objectives of the current draft, but instead the concerns of ATC and Fort McKay were with whether or not these objectives would be met. Syncrude stressed its commitment to meet the spirit and intent of the current draft, even if it was never signed by the parties, and argued that the key to success was in building a trust between the parties. This was something which it believed could not be assisted either through regulation or through approval conditions set out by the Board.

In summary Syncrude argued that it was an industry leader in undertaking initiatives to address the socio-economic issues facing aboriginal peoples. The overriding goal of those initiatives was to assist the area's aboriginal communities to become self-reliant and independent. Syncrude recognized that its operation could result in both positive and negative impacts, many of which could not be quantified, but was committed to mitigating any negative impacts to the extent that it was feasible. Syncrude rejected, however, any responsibility for either native land claims or direct compensation to aboriginals for perceived social impacts from industrial development in the area. It argued that such matters were the responsibility of government.

Syncrude also acknowledged the Fort McMurray's concerns related to the continued strain on infrastructure and community services under conditions of a declining tax base. Syncrude believed the initiatives outlined in its application were consistent with the best long term interests of the Fort McMurray but it intended to work with the city and others in the area to find regional solutions to the declining tax base and to the cost effective delivery of publicly funded services.

3 POSITIONS OF THE INTERVENERS

3.1 Technical Issues

3.1.1 Production Capability

EPECA supported the proposed SCO production increase to 12.6×10^6 m^3/yr, arguing the merits of taking full advantage of Syncrude's existing infrastructure and proven technology. It noted that Syncrude had achieved remarkable equipment reliability and that the service factors for the extraction plant had exceeded expectations for similar material handling operations.

The remaining interveners did not present any evidence to dispute Syncrude's ability to produce 12.6×10^6 m^3/yr. However, Fort McKay, SEAC, ATC, and EFONES all opposed the production increase. It was generally argued that the production increase was not in the public interest given that atmospheric emissions would also increase above the current levels. SEAC offered the following conditions that it believed should be imposed on Syncrude if the Board were to approve the 12.6×10^6 m^3/yr case:

- a 75.0 per cent reduction in SO_2 emissions,
- completion of a human health study,
- further reductions in particulate emissions,
- development of an improved regional air quality monitoring system, and
- improved bio-monitoring, chemical determinations of actual air quality, and more frequent stack surveys under non-ideal conditions.

Each of these SEAC recommendations are more fully discussed in Section 3.2.1.

Fort McKay also suggested a number of socio-economic conditions that should be imposed on Syncrude if the Board were to consider approving the 12.6×10^6 m^3/yr case. The same conditions were urged for the expansion project approval extension, the bitumen import/export operations and the project expiry date extension. These conditions are more fully discussed in Section 3.3

3.1.2 Expansion Project Design and Construction Start Date

EPECA supported the expansion project technology selection arguing that it maximized the use of existing equipment and technology, maximized product yield, and minimized the production of undesirable byproducts. It argued that the project would promote additional oil sands research and development activity providing educational opportunities for Alberta's residents. EPECA also argued that the project would have substantial economic benefits for the Province of Alberta.

Many of the interveners were opposed to an extension to the approval for the expansion project. Most argued that the expansion project was not in the public interest for environmental reasons. SEAC argued that Syncrude's expansion project was purely hypothetical and consequently lacked important information that would normally be included in an application to the Board. The major requirements identified by the interveners as necessary to make the expansion project application sufficiently complete to be able to determine if it was in the public interest included:

- an examination of in situ techniques and other options for bitumen production,
- a review of the specific sources of off-lease bitumen required for production levels greater than 14.5×10^6 m^3/yr,
- the completion of a thorough, separate environmental impact assessment,
- the development of plans to address existing concerns over the level of atmospheric emissions (Section 3.2.1), and
- the completion of appropriate health studies to assess the impact of existing levels of atmospheric emissions (Section 3.2.1).

3.1.3 Bitumen Supply

Syncrude's proposed bitumen import and export operations were also opposed by most interveners. SEAC and EFONES argued the Board had no choice but to deny this aspect of the application as Syncrude presented no specific evidence to support its request. It was suggested that details such as the sources, volumes or destinations of the bitumen imports and exports and the possible impacts on public safety and local infrastructure should be required in Syncrude's application for the Board to properly assess the merits of the proposal.

Fort McMurray identified a concern over a potential increase in truck traffic through the city. It was, however, satisfied with the manner in which Syncrude was working with it to address this issue.

EPECA supported Syncrude's proposal to import bitumen and decouple its extraction and upgrading operations. It argued that the potential for the Syncrude operation to act as a regional upgrader would support the development of smaller projects by providing a more cost effective market for production.

3.1.4 Project Approval Term Extension

The 7-year extension to the project expiry date to 2025 was opposed by most interveners. SEAC argued that Syncrude had no basis for the extension other than to preserve a 25-year operating life for the expansion project. As SEAC also believed Syncrude had no firm plans to proceed with expansion it further argued there was no justification for an extended project approval. Both SEAC and EFONES believed an extension was not in the public interest as Syncrude was offering nothing in terms of improved environmental performance or other impact mitigation. Both were uncomfortable with lengthy approval terms which provided little opportunity to ensure technology and impact mitigation choices were consistent with the environmental and social policies of a later date.

3.2 Environmental Issues

3.2.1 Atmospheric Emissions

Actual and Predicted Emissions

In general the interveners did not dispute the estimates of emissions associated with the proposed operations described in Syncrude's application. There was, however, scepticism that Syncrude could further reduce the predicted level of emissions as it indicated in the application and in its evidence at the hearing.

Flaring and Diverting

SEAC questioned Syncrude's ability to control emissions by improving its operating reliability. It noted that the incidence of flaring and diverting episodes, which were argued to be an indication of operating reliability, continued to be high and it suggested that emissions from these sources were not likely to come down without some significantly greater attention by Syncrude. It also urged that the Board require appropriate technology modifications to reduce or eliminate emissions from the diverters.

AEP also expressed concern over the level of flaring and diverting from the Syncrude facility. It noted that, in the last 4 years, Syncrude's efforts to reduce flare and diverter incidents have not had a significant effect on the level of SO_2 emissions. It was, however, satisfied with Syncrude's target of 5 t/d of SO_2 from flaring and diverting and its commitment to either a capital solution or a limiting of SCO production to maintain overall emissions within licence limits should its efforts be unsuccessful. AEP recommended that Syncrude be required to do an annual evaluation of the success of its efforts to reduce emissions associated with flaring and diverting.

Licence Limits

SEAC urged that the Board review Syncrude's current emission limits prior to any consideration of the proposals in the application before it. SEAC argued that the evidence from the hearing supported a downward adjustment of the current limits and suggested that the change be made retroactive to 1 January 1994. While SEAC acknowledged that it may not be the best judge of what the specific licence limits should be it offered the following suggestions with regard to SO_2 emissions:

- on an hourly basis, the main stack emission limit should be set no higher than 10 t/hr,

- on a 365-day average, the main stack emission limit should be set below the 1992 actual level of 208 t/d,
- on a daily basis, the total plant emission limit should be set below 240 t/d so that any significant flaring episode would result in an exceedance, and
- on a 90-day rolling average basis, the total plant emission limit should be set below 200 t/d so as to provide some incentive for improvement.

AEP advised that its minimum position with respect to SO_2 emissions was to maintain the existing limits set out in its approvals.

Federal Initiatives

SEAC highlighted Canada's international commitment to stabilize greenhouse gas emissions at 1990 levels by the year 2000. It also suggested that the current policies of the Federal Government are even more stringent, requiring a 20.0 per cent reduction from the 1988 levels by the year 2005. To put Syncrude's development proposals into perspective, SEAC provided an analysis of Syncrude's potential greenhouse gas emissions. It determined Syncrude's potential increment in greenhouse gas emissions (for the 17.6×10^6 m^3/yr SCO production case) to be in the order of 6.7 Mt/yr which it suggested was equivalent to about 10.0 per cent of Alberta's total greenhouse gas emissions in 1990. SEAC also determined that, on a national level, Syncrude's potential increase would represent 13.0 per cent of the growth in Canadian energy-related emissions projected by Natural Resources Canada (for the period 1990 to 2000) if Canada were to do nothing to stabilize emissions.

SEAC argued that the cap on greenhouse gas emissions was a national commitment and cautioned that Syncrude's incremental emissions could seriously compromise Canada's ability to meet its international obligations. It suggested that achieving this commitment would be difficult and therefore a process for allocating emissions reductions must soon be established. In recognition of these concerns, it therefore requested that, prior to any approval, Syncrude be required to demonstrate how its increase in emissions would be offset by mitigative measures or reductions elsewhere in the province. Without such consideration, SEAC argued the Board's approval of a project involving large increases in greenhouse gas emissions might serve to protect an operator from reduction allocations which would be equivalent to granting a financial subsidy. As a minimum SEAC urged that the Board clarify the extent of its jurisdictional and legal responsibility for ensuring that the environmental and economic impacts of increased greenhouse gas emissions in Alberta are considered. Although emphasizing that it did not intend to single out Syncrude on this issue, AEP suggested that, as a large producer of greenhouse gas emissions, Syncrude should be taking a lead role on this issue for the industry. It also recommended that Syncrude should undertake to provide an inventory of greenhouse gas emissions and a further examination of the potential to reduce these emissions through improved energy efficiency.

SEAC also highlighted Canada's international commitments on SO_2 emissions reduction as considered within the framework of the Helsinki Accord. The Accord had the general goal of capping emissions at a level equivalent to a 30.0 per cent reduction from 1985 levels.

Emissions Reduction

SEAC suggested that Canada's federal commitments required that SO_2 emissions reduction technology be considered when expansions or modifications to existing facilities take place. It acknowledged

Canada's official negotiating position which accepted the application of best available technology for new facilities only, but argued that Alberta precedent (as demonstrated in the case of gas plants and the associated sulphur recovery requirements) also considered application of such technology in the case of significant modifications to existing facilities. SEAC noted that ERCB IL 88-13 (Sulphur Recovery Guidelines - Gas Processing Operations) requires sour gas facilities to meet more stringent sulphur recovery requirements when either the sulphur inlet volume is increased by 25.0 per cent or significant new sour gas volumes are to be processed. SEAC also noted that during the 1988 SERG process, the Board required an independent review of the viability of retrofitting main stack emission reduction technology and ultimately conditioned its approval to require a further review in 3 years.

It was SEAC's view that Syncrude's application was clearly an expansion proposal and therefore required a re-evaluation of SO_2 emission reduction technologies. It acknowledged reports on this subject submitted to the ERCB by Syncrude at the end of 1991, but argued these and the review provided at the hearing were inadequate. Although SEAC admitted it did not have expertise in emission reduction technology, it tabled a CH_2M HILL Engineering Ltd. report (prepared for Environment Canada) which detailed possible technology options which could be applied at the Syncrude facility. Based on the assessment contained in this report and financial and economic information provided by Syncrude, SEAC concluded that SO_2 emissions reduction was economically viable in Syncrude's case. Based on these favourable economics and growing public concern over human health and environmental damage associated with the emissions from the existing plant, SEAC argued that the Board should not approve Syncrude's application without requiring the installation of SO_2 emissions reduction technology at the Mildred Lake facility within 3 years.

SEAC and EFONES acknowledged plans by Suncor to pursue SO_2 emissions reduction, however, it was suggested that this may not be sufficient to negate the need for similar actions on the part of Syncrude. At the very least, SEAC felt the Board should require an independent assessment of the issue similar to that conducted during the SERG process.

AEP took the position that, given what it considered incomplete knowledge on the subject of the dispersion and deposition of acid-forming emissions, it was the responsibility of Syncrude to make a reasonable effort to minimize SO_2 emissions. It specifically identified flaring and diverting emissions as an opportunity for reduction, as described previously in Section 3.2.1 — Flaring and Diverting.

With regard to other emissions, SEAC also urged the Board to require further actions to control fugitive hydrocarbon emissions from Syncrude's operation. Some suggestions included:

- improved recoveries in the NRU,
- enclosing the API separator plant,
- reducing the surface area of the effluent pond, and
- stringent expectations for Syncrude's leak detection and repair program.

SEAC's position with respect to greenhouse gas emissions reduction has been previously described in Section 3.2.1 — Federal Initiatives.

AEP supported improvements to the NRU which had been proposed by Syncrude, and strongly urged that the initiative proceed as quickly as possible. AEP also supported a continuation of Syncrude's program for NO_x emissions reduction which included the installation of low NO_x burners and energy efficiency improvements.

Fort McMurray originally questioned the atmospheric emissions control technology proposed by Syncrude in the expansion project, however through consultations with Syncrude, it became satisfied that the applicant was taking appropriate measures to control emissions. It also noted that it was satisfied that the Board would ensure appropriate technology was used.

Sulphur Deposition

EFONES focused its intervention largely on the issue of wet and dry sulphate deposition. It did so because the issue was central to its objection to the application and because it believed it could provide new information which it considered was highly relevant but had not been examined by either Syncrude or its consultants in the preparation of the application.

EFONES argued that its evidence showed that the Fort McMurray precipitation pH results used by Syncrude's consultants to predict wet sulphate deposition were erroneous due to the collector location. It advised that, since the summer of 1988 when the same wet-only precipitation collector was relocated to a less compromised location, results indicated precipitation at Fort McMurray to be acid with a pH of around 4.8 to 4.9. EFONES noted that revised Syncrude model predictions based on these lower rain pH values result in wet deposition estimates which are consistent with those provided in the EFONES intervention. It concluded that while sulphur deposited by precipitation wet fall is lower than initially projected by Syncrude's consultants, the precipitation is definitely acidic with significant acidifying potential.

In the case of dry deposition, EFONES relied on the work of Dr. M. Nyborg and others who, in the mid 1970s, made sulphur deposition measurements in the oil sands area. EFONES focused on the throughfall and stemflow measurements in the Nyborg work, as it understood that the technique was now generally accepted as an indication of total sulphur deposition in forested areas. It compared the Nyborg measurements with deposition estimates contained in Syncrude's application and found that the values predicted by Syncrude using the ADEPT2 computer model were lower for sites within 50 km and unreasonably lower for sites beyond 50 km. **Table 5** contrasts EFONES predictions of average sulphate deposition and effective acidity (within a 50-Km radius of the plant and based on current Syncrude emissions) with Syncrude predictions included in the application.

TABLE 5: COMPARISON OF WET AND DRY DEPOSITION PREDICTIONS

	PREDICTED SULPHATE DEPOSITION (kg SO_4/ha/yr)		**EFFECTIVE ACIDITY (kmol H^+/ha/yr)**
	WET	**DRY**	
EFONES	6	22	0.47
SYNCRUDE	8	9	0.18

EFONES largely attributed the differences in predicted deposition to the use of the ADEPT2 model. EFONES suggested that the plume depletion estimate of the ADEPT2 model was inconsistent with the model's wet and dry deposition estimates. EFONES attributed this to either errors in the SO_2 concentrations used in the modelling or mathematical errors in the model itself. It also found that Syncrude's consultants erroneously reported model outputs of zero as though they were calculated, which it believed also helped explain the differences in projections at greater distances from the source.

EFONES concluded that Syncrude's ADEPT2 model projections should be given little or no weight by the Board as EFONES had shown it may possibly contain errors and since the model had never been validated.

In October 1993, EFONES returned to and obtained soil samples from 7 of the 17 permanent soil plots used in the earlier Nyborg work. The samples were analyzed for pH and total sulphur content and from this work EFONES concluded that, at most sites, soil pH measurements were consistent with sulphur deposition rates expected at those sites on the basis of throughfall measurements and other observations. It was also concluded that for at least three of the seven sites, the measured increases in sulphur in the mineral soil were consistent with sulphur deposition estimates based on the earlier Nyborg throughfall measurements at those sites.

Fort McKay and SEAC supported the concerns expressed by EFONES related to sulphur deposition. Fort McKay's consultants recommended that:

- a routine method for measuring dry deposition of sulphur compounds be developed and used in the oil sands region, and
- air quality models should be validated prior to their use.

AEP noted the difference in opinions of the various parties at the hearing and concluded that significant uncertainty exists with respect to the wet and dry deposition of acid forming emissions.

Vegetative Effects

As part of its evidence, SEAC presented a review of existing scientific literature which it concluded supported its view that observable impacts on regional vegetation were occurring as a result of atmospheric emissions from the oil sands facilities. It specifically highlighted literature which reported increased stress in lichen communities and increased levels of heavy metals in plant tissues. It argued that the available evidence supported its view that increases in vegetative impacts could be correlated to regional increases in emissions, particularly SO_2. SEAC conceded that the full extent, nature and severity of these impacts were not fully understood. However, SEAC strongly disagreed with any suggestion that impacts were either insignificant or localized. Based on these uncertainties, SEAC believed that Syncrude's proposed development and associated increase in emissions posed an unacceptable risk of significant future impacts on vegetation. It therefore argued that action should be taken to reduce, rather than increase, emission levels.

SEAC also argued that Syncrude's bio-monitoring program was limited in its ability to detect and predict the full range of possible effects on vegetation. It concluded the system had failed to properly integrate its various components and SEAC supported the request by Fort McKay to improve the biomonitoring program. It further criticized Syncrude for the lack of an environmental management program which linked its monitoring results to some form of response plan.

SEAC urged the Board to, at a minimum, require Syncrude to enhance its bio-monitoring programs for vegetation stress indicators for toxin and heavy metal-bio-accumulating species and for soils and trees.

Ambient Air Quality

SEAC argued that existing emission sources associated with oil sands facilities were causing a significant number of violations of Alberta's ambient air quality objectives and it suggested that a zero tolerance approach with regard to these violations would not be unreasonable.

SEAC also argued that significant improvements to the existing approach to the management of regional air quality were required. It acknowledged past efforts by SERG to address this issue but, was of the view that many of the improvements and initiatives contemplated in the SERG report had not yet been implemented. It therefore recommended that any approval issued by the Board be conditional on Syncrude working with all interested stakeholders to jointly develop a management system that is consistent with the principles embodied in the Clean Air Strategy for Alberta — Zonal Air Quality Management System recommendations. SEAC acknowledged the possibility that RAQCC could be modified to serve in this role, but not without substantial changes and improvements.

AEP also supported the use of RAQCC or a modified RAQCC to promote dialogue to help address air quality issues. It suggested the multi-stakeholder process should look at issues such as predicting and measuring acidic deposition, environmental effects of atmospheric emissions, and more comprehensive ambient monitoring.

Most interveners supported improvements to the existing regional air monitoring system which is operated by Syncrude, Suncor and AEP. In this regard, the recommendations of Fort McKay were generally supported by the interveners. Fort McKay observed that the existing monitoring network did not measure all air contaminant parameters consistently at all stations. This was considered significant because it believed that a thorough air quality assessment required that monitoring protocols be standardized and subject to a quality assurance and quality control program. It was suggested that any monitoring should be designed so that it is routine, unambiguous, and has the support of all stakeholders. Specific recommendations included the following:

- particulate emissions should be monitored and measured in terms of their size ranges and chemistry at Fort McKay, Fort McMurray, Suncor, and Syncrude,
- hydrocarbons should be characterized and quantified at each source and routinely monitored in Fort McKay, Fort McMurray, Suncor, and Syncrude for, at minimum, methane and non-methane hydrocarbons,
- air quality should be monitored, measured, and evaluated on a regional basis rather than by individual operators, and
- air quality in the oil sands region should be evaluated on an annual basis by a neutral party and reviewed by a multi-stakeholder group.

Fort McKay believed that taking a regional approach to the monitoring of oil sands airshed emissions could involve fewer monitoring stations than currently existed but cautioned that those stations would likely need to be better equipped. It was also acknowledged that existing monitoring stations could require relocation to optimize the performance of the monitoring network.

In addition to supporting the recommendations of Fort McKay, SEAC also indicated a desire for improved episodic monitoring and response.

Health Impacts

A number of interveners raised the issue of human health impacts. Specific comments and suggestions were made by both SEAC and EFONES with regard to Syncrude's commitment to participate in discussions on the topic with all concerned stakeholders. SEAC welcomed the opportunity for such discussions, but also felt some urgency in beginning the dialogue and suggested that the discussion be initiated as early as 31 March 1994.

SEAC asked that the Board require Syncrude (and Suncor if appropriate) to finance a meaningful and comprehensive health study that would be conducted by an independent and credible third party. It felt that the study should encourage participation from all stakeholders including industry and regulatory agencies and stressed that susceptible individuals must be used in accumulating data on human health effects. It argued that stakeholder participation should occur at all levels of the study including:

- the selection of an independent, third-party contractor,
- the development of the terms of reference, and
- the analysis and evaluation of the results.

SEAC stated that if the study were to substantiate concerns regarding the human health effects of emissions, it would expect the Board to require an immediate reduction of emissions to pre-expansion levels, followed by a review of potential options for further reductions.

EFONES also stated that a proper epidemiological study in the region was long overdue, and supported the suggestion that an independent third party should initiate and oversee the study. It was suggested that the Board was well positioned to perform this role, as well as control funding. EFONES stated that a body of anecdotal information existed in the Fort McMurray area which could be used in future epidemiological studies.

EFONES also commented on the risk assessment study tabled by Syncrude. It did not consider this study as realistic or particularly relevant since it considered only Syncrude's main stack emissions in the absence of other sources and background levels. It was argued the value of the study was further limited by the fact that the conclusions were based on input data from the ADEPT2 model which EFONES considered invalid.

AEP supported the concept of a community-based participatory health study and recommended that Syncrude be required to participate. It believed the study should, at minimum, continually monitor a segment of the population in terms of ambient exposure, biomarkers, and health outcomes.

3.2.2 Reclamation

Need for Approval and Jurisdiction

Fort McKay took no position on the Board's jurisdiction and extent of authority with regard to reclamation, but did ask that the matter be clarified in the decision report. It acknowledged that disposal of waste, which may include fine tails, was clearly within the Board's jurisdiction, but it left it to the Board to clarify whether that jurisdiction extended to making rulings on the final end land use of the reclaimed site.

Fort McKay supported conceptual approval of the proposals for fine tails reclamation as it concurred there was some urgency to address this aspect of Syncrude's reclamation plans. This support was, however, conditional on the successful demonstration of the technology by the development of a full scale demonstration lake (i.e. the base mine lake).

With regard to the overall site reclamation, Fort McKay was unsure of the nature and extent of the conceptual approval being sought by Syncrude. In any event, it suggested there were no cost or other urgent issues to justify approving Syncrude's site reclamation plans at this time. It argued that Syncrude could obtain 5-year development and reclamation approvals (now termed conservation and reclamation or C&R approvals) from AEP which would allow it to conduct any required activities. Fort McKay could therefore find no reason to eliminate any reclamation options from Syncrude or the stakeholders by approving this aspect of the application at this time. It stated a particular conceptual plan should only be approved when Syncrude had successfully demonstrated that it could meet previously agreed upon criteria.

SEAC did not accept that the Board had jurisdiction over reclamation matters, nor did it agree that reclamation was a legitimate aspect of a scheme for which the Board grants approval. It noted that the Oil Sands Conservation Act and Regulation does not even mention reclamation, nor does it grant specific authority to issue conceptual approvals. SEAC argued that reclamation evidence was put before the Board to aid in determining whether reclamation could indeed be accomplished in order that the Board might exercise its jurisdiction in determining whether a project was in the public interest having regard to environmental matters. SEAC speculated that Syncrude sought reclamation approval from the Board in order to better define its reclamation liabilities and improve its prospects of attracting new investment. It also suspected that Syncrude would use an ERCB approval to put pressure on AEP so that it would similarly support Syncrude's reclamation plans and grant a new C&R approval.

SEAC argued that Syncrude's reclamation plans were a matter for which AEP had specific authority and that this authority could be seen in the series of earlier D&R approvals issued by AEP. It urged that the Board ensure any conditions the Board might impose did not preclude AEP from exercising its proper regulatory discretion on these matters.

AEP appeared at the hearing to ensure that the Board was aware of the implications that granting a conceptual reclamation approval would have on the mandate and responsibilities of AEP. It argued that such approval would act to limit the number of options considered, resulting in applications to AEP which dealt only with those plans approved by the Board. It suggested that this could also imply that approvals by a decision maker at AEP could only deal with the fine tuning of the Syncrude plans.

AEP argued that approvals granted by the Board under the Oil Sands Conservation Act were intended to consider the broader issue of whether a project was in the public interest. It advised that, on the other hand, approvals under the Environmental Protection and Enhancement Act were narrower in focus, requiring projects to meet the environmental standards imposed by the Act and Regulations. AEP noted that neither the Board's legislation nor its guidelines make reference to conceptual reclamation approvals and therefore in its decision, the Board will need to make clear whether such an approval exists and, if it does, where its authority ends. In any event, it argued the decision of the Board would need to be consistent with the present and future regulatory decisions of other jurisdictions and should clearly be made conditional on acquiring appropriate approvals from AEP as well.

Overall Site Reclamation

Fort McKay was the only intervener that had specific comments on Syncrude's site reclamation proposals. It argued that approval of the proposed site reclamation plan should be denied as it did not accept that Syncrude had sufficient data to satisfactorily demonstrate the viability of its proposed site reclamation techniques. It questioned whether adequate stakeholder review and acceptance had been obtained, and it argued that Fort McKay would be exposed to considerable risk if this concept were approved without its input. Specifically, Fort McKay was opposed to Syncrude's proposal to incorporate grasslands into the final landscape. It questioned whether this would be a self-sustaining feature and it indicated a preference for a final landscape that incorporated native species and habitats. Fort McKay suggested that considerably more work and a higher degree of scientific certainty is needed before it would support any site reclamation concept. It suggested that an independent "blue ribbon" review panel be established to critique any reclamation plans proposed by Syncrude. It also argued that the final plan should be combined with Suncor's reclamation plan to ensure a more comprehensive regional integration.

All interveners agreed that Syncrude must continue research into a variety of reclamation techniques and not limit itself to one particular technology.

Fine Tails Reclamation

Fine tails reclamation, and in particular Syncrude's water-capped fine tails reclamation proposal, was a primary focus of the Fort McKay intervention. Fort McKay conducted a detailed review of Syncrude's fine tails reclamation proposal and supporting research work. It concluded that formal and final approval of Syncrude's plans was premature at this point in time because it believed a number of technical issues had not been satisfactorily addressed. It was, however, prepared to support conceptual approval of Syncrude's plans provided implementation occurred in a phased manner which would allow for further research and a proper demonstration of the technical viability of the approach. To satisfy this concern, Syncrude and Fort McKay entered into an agreement which resulted in Syncrude's proposal (tabled during the hearing) to develop the base mine lake. In the agreement Fort McKay supported conceptual approval of Syncrude's fine tails reclamation plans provided that Syncrude:

- proceeded with the development of the base mine lake in order to demonstrate the concept feasibility,
- agreed to report to and consult with stakeholders on an ongoing basis as the demonstration proceeded,
- continued a range of scientific investigations, as discussed with Fort McKay, to support the development and demonstration of the concept,
- continued research on alternative fine tails management and bitumen extraction technologies that showed potential to reduce the volume and improve the characteristics of fine tails,
- continued to publish its research findings,
- agreed to consult with Fort McKay on progress and future research direction, and

- agreed to prepare a new environmental assessment and seek appropriate regulatory approval for any remaining fine tails lakes in its reclamation plan should the concept be satisfactorily demonstrated.

Although Fort McKay endorsed the concept, it did not support granting a specific approval, at this time, for the details of the base mine lake. It argued, as contemplated in its agreement with Syncrude, additional stakeholder consultation was required to reach consensus on specific design features, performance standards, and monitoring criteria. It therefore recommended that, prior to specifically approving the demonstration lake, the Board should require Syncrude to conduct appropriate research and continued investigations on the following issues:

- the rate of release and composition of pore water,

- the characterization of concentrations and degradation rates of toxic components in pore water,

- the extent of the salinity gradient and the potential inhibition of thermal mixing,

- the viability and potential use of freeze/thaw techniques for fine tails consolidation, and

- the volume, chemical and physical properties of the water capping layer, including the volume and characteristics of fine tails to be stored.

AEP also supported the concept of the base mine lake but did not support conceptual approval of the water capped fine tails reclamation proposal. It noted that although an additional application would not be required, Syncrude must still obtain the appropriate approvals from AEP.

SEAC was unable to support the conceptual approval of the water-capped fine tails reclamation scheme for various reasons. In addition to the question of jurisdiction, it had concerns with the technical aspects of the water-capping proposal, including design features, water quality, timing, and consequences of failure. It suggested that a more definitive plan should be submitted to AEP before the granting of any approvals is considered. SEAC and EFONES also argued that the Syncrude/Fort McKay agreement on the base mine lake was lacking in required details, and the agreement itself demonstrated that neither Syncrude nor Fort McKay understood the ERCB's function with respect to approval of oil sands schemes.

3.2.3 Fine Tails Management

Fort McKay was of the view that the model Syncrude used to forecast the volume of fine tails could be under-predicting by as much as 30.0 per cent. While this would have obvious implications for Syncrude's planning, it was conceded by Fort McKay that Syncrude's fine tails management and reclamation proposals could accommodate the higher volume.

Fort McKay reviewed Syncrude's plans regarding engineered tails and identified two concerns. The first, and most significant, was based on what it believed to be a lack of evidence that engineered tails would in fact reduce the amount of "fine tails formers". While it acknowledged some evidence of an increased capture in the beach of clay particles less than the 22 micron size, it argued that Syncrude had no evidence of an overall reduction in fine tails volume. Fort McKay therefore concluded that it was conceivable that the volume of fine tails may not be reduced by this technique. The second concern was the stability of sand dumps that were constructed using engineered tails. Fort McKay believed the potential existed for instability in the dumps as a result of the highly variable nature of the tailings stream used as construction material. It was acknowledged, however, that with proper monitoring during construction adequate modifications could be made to resolve its concerns.

Fort McKay noted that it did not have the time or resources to retain the necessary expertise to examine the range of other techniques being investigated by Syncrude or others that had the potential to reduce the volume and/or toxicity of fine tails. It recommended that the Board direct Syncrude to pursue appropriate research in this area and require Syncrude to file a comprehensive 3 to 5-year research plan for the Board's approval. Fort McKay singled out what it considered promising developments related to the chemical treatment of fine tails and asked that the Board direct Syncrude to expedite this research and report to the Board and other stakeholders on its progress in 12 to 24 months.

AEP also asked that Syncrude be directed to continue research into other fine tails management technologies. It recommended that Syncrude be required to report to the Board and AEP on this activity on an annual basis. AEP also argued that Syncrude should be directed to incorporate a variety of fine tails management and reclamation techniques into its ongoing operations to keep the current and future fine tails inventory at a manageable level.

3.3 Socio-economic Issues

In June 1993 Fort McKay surveyed individuals in the community to assess support for Syncrude's proposed expansion. The survey also assessed support for forestry activity in the area and examined the residents' views of priorities for improvements to the facilities, services and the infrastructure in the community. Approximately half of the residents of Fort McKay did not support Syncrude's application. Of those, about two-thirds would conditionally support the application with appropriate commitments by Syncrude to address concerns regarding improved pollution controls, employment opportunities, and training programs.

Fort McKay was of the view that there had never been a thorough documentation of the socio-economic circumstances of its community or the existing and potential impacts experienced by residents as a result of the oil sands operations in the region. It presented evidence to counter what it considered public and industry perceptions that the community had successfully coped with and adjusted to the impacts resulting from the local oil sands industry.

Fort McKay observed that the land disturbance and population growth associated with the oil sands development had resulted in decreased animal populations on traditional lands. This impacted opportunities for traditional activities such as hunting and trapping. It was also argued that traditional lands played an important role in other social, cultural, and recreational activities associated with their way of life, and these too were suffering as a result of oil sands development activity. It argued that the hunting, fishing, and trapping rights of Canada's aboriginals were protected under the Constitution and reinforced by Treaty 8 which guaranteed protection of the traditional lifestyle of Fort McKay and other First Nations in the region. It perceived a general lack of recognition of these rights, particularly rights related to compensation. It argued that compensation for the loss of traditional native lands had a well established precedence and growing legal basis.

While it acknowledged some limited economic benefits from the oil sands operations, Fort McKay argued that these benefits did not mitigate the many socio-economic impacts suffered by the community. It also recognized past efforts to address these socio-economic concerns, namely the Fort McKay

Interface Committee (FMIC) and SERG. However, it argued that most of the socio-economic concerns raised during the SERG process were not satisfactorily acted upon by Syncrude and it expressed disappointment over the level of commitment and progress made with regard to issues brought forward to FMIC. Fort McKay felt that the only way real and meaningful progress could be made on its socio-economic issues would be for the Board to require specific actions by Syncrude.

Fort McKay therefore recommended that the Board address its socio-economic concerns by conditioning any approval of the application to require that Syncrude:

- assist Fort McKay with the development and implementation of a plan specifically designed to compensate for the loss of use of traditional lands. The plan would be completed and submitted to the Board within 12 months with implementation reviewed annually thereafter by the Board.

- assist Fort McKay with the development and implementation of long-term initiatives to offset current and potential future adverse impacts on the community. A plan detailing these initiatives would be submitted to the ERCB within 12 months with implementation reviewed annually thereafter by the Board for a period of 10 years.

- provide Fort McKay a maximum of $100,000 annually for 5 years to support community participation in regional environmental consultation activities including RAQCC, FMIC, and reclamation planning discussions.

- assist Fort McKay with the development and implementation of initiatives designed to optimize short and long-term economic benefits which the community would derive from Syncrude's operation. A plan detailing these initiatives would be submitted to the ERCB within 12 months with implementation reviewed annually thereafter by the Board for a period of 10 years.

- in consultation with other stakeholders, design and undertake a comprehensive study to assess the full range of physical, mental, and emotional health impacts of the oil sands developments on the Fort McKay community.

Fort McKay also requested that the Board recommend to the provincial cabinet that the Alberta government:

- provide Fort McKay a portion of the taxes paid by Suncor and Syncrude to ID-18. The funds would be used to help it pay for services and programs aimed at offsetting the adverse socio-economic impacts of regional resource development,

- work with Syncrude and Fort McKay on efforts to plan and implement community-directed programs to provide additional government services to mitigate socio-economic impacts on the community,

- pursue supportive and complementary involvement in the initiatives that Fort McKay has recommended the Board direct Syncrude to undertake, and

- provide additional housing and services to the Fort McKay Metis community.

Fort McKay was of the opinion that the Board had the mandate and authority to impose conditions on Syncrude aimed at mitigating the socio-economic impacts experienced by its community. It argued there were no legal barriers to the Board imposing the conditions sought by it and suggested that the Board's own legislation required that it ensure resource development occur in the public interest having regard for the social and economic effects. In the event that the Board concluded it did not have such jurisdiction, Fort McKay asked that the Board define, in the decision report, the extent of its mandate, authority and jurisdiction on these matters.

ATC generally echoed Fort McKay's concerns, but also presented evidence to highlight deficiencies in Syncrude's socio-economic impact assessment (SEIA) and to demonstrate the ineffectiveness of Syncrude's past aboriginal policies.

In general ATC considered the SEIA deficient because of its failure to address the socio-economic circumstances of aboriginal peoples in the region and its lack of specific details regarding the programs and policies for aboriginal training, recruitment and employment. ATC argued that Syncrude's commitment to aboriginal employment and economic development was not borne out by the evidence. It believed the limited success was due to a lack of accountability, poorly defined policies, outdated programs, and a failure to consult with aboriginal stakeholders when developing a strategy.

ATC acknowledged efforts by Syncrude to address aboriginal concerns through accords with the ANDC. It characterized these attempts as largely unsuccessful and it blamed this on Syncrude's own aboriginal policies and programs. It argued that the only way to ensure that the current draft ANDC accord would be successful would be for the Board to require that Syncrude develop and implement the programs contemplated by that accord. Without such conditions, ATC would not support Syncrude's application.

ATC specifically recommended that the Board condition its approval to require that Syncrude:

- submit a revised SEIA that corrects the deficiencies identified by ATC or submit a comprehensive report on aboriginal and employment development initiatives, with either of these to be prepared in consultation with the First Nations in the region,

- respond, within 2 months, to the issues raised in the 28 July 1993 ATC discussion paper which identified socio-economic issues and a process to deal with them in the short term and on an ongoing basis,

- in consultation with ATC and ANDC, design and implement comprehensive employment equity and business development policies and programs. The programs would be completed and submitted to the Board within 12 months with implementation reviewed periodically by the Board,

- in partnership with the provincial and federal governments, fully fund the ANDC for a 5-year period,

- assist each member of the ATC with planning and implementing initiatives which result in short and long term economic benefits to the respective First Nations. The initiatives would be designed and submitted to the Board within 6 months with implementation reviewed annually by the Board for a period of 10 years, and

- provide $50,000 annually to each First Nation to assist with the implementation of community development plans.

ATC also requested that the Board advise the Provincial Cabinet of the concerns of the First Nations and asked that it recommend to Cabinet that the government of Alberta:

- assist Syncrude and the ANDC in establishing a regional forum for ongoing consultation on aboriginal employment and business issues,
- join with the federal government to fund the activities of the ANDC for a 5-year period and work with it to ensure the goals of the draft accord are achieved,
- join with the Federal Government to ensure substantial new sources of funding, including a portion of the ID-18 tax revenue, are provided to First Nations to cope with adverse socio-economic impacts,
- lead a coordinated effort of the Provincial and Federal Governments, Syncrude and the ANDC to address aboriginal education, training, and employment programs,
- ensure that favourable tax or fiscal agreements with Syncrude are conditional on Syncrude achieving proportional aboriginal representation in its workforce by 1997, and
- ensure that favourable fiscal regimes for Syncrude's expansion project would be accompanied by the establishment of federal and provincial equity or loan funds to assist aboriginal businesses.

Fort McMurray raised concern with the increasing strain on its infrastructure and community services. It felt that a decreasing tax base (associated with the declining work forces at Suncor and Syncrude) combined with increasing family size were creating an increased demand for schools, recreation facilities, and other municipal services. It was, however, satisfied that the issue could be properly addressed through ongoing dialogue with Syncrude.

4 BOARD VIEWS

4.1 Technical Issues

4.1.1 Production Capability

The Board believes that Syncrude's proposal to increase SCO production capability without major plant modifications would result in an efficient use of existing facilities and infrastructure, considering Syncrude would also maintain extraction hydrocarbon recoveries and upgrading SCO yields at or above current levels. The Board therefore accepts that Syncrude's proposal represents an orderly and efficient use of the province's energy resources.

The Board is also satisfied that Syncrude's programs to debottleneck existing equipment and increase associated service factors have the potential to significantly improve the performance of the existing plant, and enable it to operate at SCO production levels approaching 12.6×10^6 m^3/yr. The increased coker rates required to achieve the higher production will also, however, result in increased SO_2 emissions. The Board's views on appropriate atmospheric emissions levels are discussed in more detail in Section 4.2.1. The Board also remains concerned that increased service factors can, without careful monitoring and a willingness to curtail production if necessary, eventually result in proportionately more severe plant upsets and associated flare and diverter emissions. The Board's views on these risks are discussed in Section 4.2.1.

4.1.2 Expansion Project Design and Construction Start Date

The Board is satisfied that the technology and design approved for the expansion project in 1988 remains appropriate under current regulatory standards and expectations. The Board is therefore prepared to extend, to 31 December 1997, the date by which expansion construction must commence. It notes that Syncrude's current technology choices differ from the 1988 proposals only in the use of hydrotransport technology. The Board believes that hydrotransport may indeed be an improvement, but believes Syncrude should continue to develop and test that technology in the context of its existing operations, confirm performance to verify the expected benefits, and advise the Board of all results as operational tests are completed before finalizing its incorporation into the expansion project. In this regard the Board notes Syncrude's efforts in 1993 to demonstrate the technology through the development of an extraction auxiliary production system. The Board is prepared to approve the continued operation of this system and in principle has no objection to further modifications to the existing extraction plant to incorporate this technology. For that matter the Board encourages Syncrude's aggressive investigation and adoption of any other new developments in extraction technology that can deliver an improved balance of resource recovery efficiency, lower economic cost and reduced environmental impact.

The Board also notes that Syncrude is continuing to review its production capacity to optimize the expansion project economics and increase the likelihood that expansion will proceed. The Board notes that this effort leaves a question as to the actual production capability following expansion, but believes that, so long as the incremental capacity does not exceed that which was originally considered and approved (i.e. 5.0×10^6 m^3/yr), there is no need for a future amended application. The Board would, however, expect Syncrude to apprise the Board of the details of its final project design in advance of its implementation. The Board accepts that Syncrude could, within the term of the approval, achieve an SCO production capacity of 17.6×10^6 m^3/yr from the Mildred Lake facility.

4.1.3 Bitumen Supply

The Board recognizes that, in order to sustain production at higher levels for the existing approval term or an extended term, Syncrude would require additional bitumen production from the existing lease or other sources. The Board believes that the additional mining areas identified by Syncrude within its existing lease are therefore necessary and should be approved, with the exception of the West Mine which would be considered when more definite plans are available.

The Board believes that the practice of importing and exporting bitumen to or from the Syncrude facility is consistent with responsible development, efficient use of existing facilities, and resource conservation. It believes that approving bitumen imports will provide an Alberta market for domestic crude bitumen production. This may serve to support the development of new regional production operations and lead to more timely development of Alberta's oil sands. While the Board recognizes the concerns of interveners regarding the actual volumes that might be imported, the Board does not intend to impose a limit on import and export operations. The Board is satisfied that the concerns raised by interveners, including transportation issues, can be more effectively addressed through the regulatory approval processes that would be required for any new or significantly expanded bitumen production, transportation, or processing operation in the province. The Board notes that the city of Fort McMurray has indicated that it has a process to deal with industry on the issue of truck traffic.

4.1.4 Project Approval Term Extension

The Board believes that an extended approval term would benefit the economics of both the contemplated improvements to the current operation and the expansion project. It believes that, for a significant capital project like the expansion proposal, an approval term that supports a 25-year operating life is reasonable and justified. In response to the concerns of some stakeholders who were uncomfortable with long approval terms, the Board notes that it has the authority to reopen any approval issued by it should significant environmental, conservation, or other issues arise at a later date. In addition, AEP issues approvals with respect to reclamation and other environmental matters which must be renewed on a much more frequent basis. These approvals should provide an additional, shorter-term opportunity for public input.

4.2 Environmental Issues

4.2.1 Atmospheric Emissions

A significant portion of the hearing focused on local and regional environmental impacts resulting from atmospheric emissions from both the Syncrude and Suncor facilities. Although there were some notable exceptions (which are referenced below) based on the available evidence, the Board in general accepts Syncrude's assertion that any impacts which have occurred in the past have been localized or of short duration. At the same time, however, the Board does not believe that Syncrude has been sufficiently diligent in the collection of scientific evidence which would adequately confirm the company's assertions that these effects would not develop into long term adverse conditions. The Board believes that the ongoing absence of such information could eventually result in an increasingly conservative approach to the setting of emission limits for oil sands operations. The Board would therefore expect that the energy industry, working with all the area stakeholders, will begin to assume a clearer leadership role in the collection of regional data designed to ensure that airshed-related impacts are properly measured and understood.

Should such data indicate that emission limits are not appropriate, the Board is prepared to re-examine and to modify licensed limits as necessary.

Actual and Predicted Emissions

The Board finds little reason to dispute Syncrude's predictions of the emission levels that would be associated with its proposed development scenarios. It notes, however, that in the case of SO_2 emissions for the 12.6×10^6 m^3/yr case, Syncrude's predictions are very close to the existing licence limit and may in fact be somewhat optimistic given the predicted sulphur recovery and levels of flare and diverter emissions. The Board expects Syncrude to develop and implement a program to demonstrate to all stakeholders due diligence in its efforts to reduce or eliminate emissions wherever practical. The Board would expect annual updates on this program.

Flaring and Diverting

The Board believes that current levels of flare and diverter SO_2 emissions are too high and should be reduced. Several factors, including poorer dispersion characteristics, make higher levels of emissions from the diverter stack particularly unacceptable. Further, the Board believes that emissions from these sources may impact on Syncrude's ability to achieve its predicted emission levels for the entire facility. The Board acknowledges Syncrude's intent to reduce these emissions to an annual average of 5 t/d or less and believes that, if successful, this would represent a reasonable level of emissions from these sources. The Board notes Syncrude's undertaking to improve and modify its operations to limit flare or diverter stack emissions to no greater than an annual average of 5 t/d, irrespective of the magnitude of the total facility emissions. Progress on this initiative should be reported in Syncrude's annual progress report on its efforts to reduce total plant emissions.

Licence Limits

The Board believes that the existing SO_2 emission limits, as contained in the AEP approvals, remain appropriate and finds no compelling evidence of adverse effects caused by these emissions that would support a reduction to these limits. The Board believes Syncrude will be operating at or very close to its current emission limits under the 12.6×10^6 m^3/yr production scenario and therefore expects Syncrude to restrict SCO production or seek capital solutions if emissions cannot be maintained below these approved levels. The Board believes this lack of operating margin will provide Syncrude with sufficient incentive to pursue further reduction opportunities and be successful in limiting SO_2 emissions.

The Board believes that the AEP emission limits for NO_x and particulates also continue to be acceptable.

Federal Initiatives

The Board acknowledges the broad federal initiatives and commitments for the stabilization and reduction of SO_2 and greenhouse gas emissions and believes that federal/provincial agreements will be necessary to implement the commitments. It notes that these initiatives have not as yet progressed to the point where national policies have been developed that define the levels of reductions which are required, the sectors of industry to which any reductions may be mandated or the circumstances under which any reductions might apply to those sectors. The Board is satisfied that Syncrude's energy efficiency and other initiatives are a reasonable acknowledgement of the federal commitments and notes that, if and when definitive national programs are established, Syncrude will be subject to those requirements under the same rules as any other industrial operation.

Environmental Effects

The Board accepts that the evidence in general supports Syncrude's position that its SO_2 emissions are not resulting in either widespread or irreversible environmental damage in the region. The Board believes that there is some evidence of SO_2-related vegetative stress, but notes the evidence produced at the hearing appears to indicate that the impact is limited and primarily confined to the Athabasca River valley. Because of the location and elevation of its main stack and the associated effect on dispersion, the contribution of Syncrude's emissions to vegetative impacts within the Athabasca River valley is believed to be less than the impact from other sources within the valley and in particular Suncor's main stack. The Board notes that a major reduction of Suncor main stack SO_2 emissions has been required by the province and that Suncor has committed to proceed with appropriate modifications to its facility in a timely fashion. Given this, the Board does not believe there is a demonstrated need at this time for a significant reduction in Syncrude's emissions in order to protect area soils and vegetation.

The Board considers Syncrude's proposals for the management and control of NO_x, hydrocarbon, CO_2, and particulate emissions appropriate. However, the Board expects Syncrude to continue to investigate and implement reduction initiatives, particularly for fugitive emissions, whenever practical.

The Board notes the concerns expressed by various interveners, EFONES and Fort McKay in particular, regarding the adequacy of regional ambient air quality monitoring and biomonitoring. These concerns do have merit and Syncrude's ambient air quality monitoring and biomonitoring programs warrant further review. Given the magnitude of emissions from the Syncrude's facility, the Board considers it prudent for Syncrude to implement, as soon as practical, significant improvements to its monitoring programs. In addition, the Board will require periodic submissions detailing the results of such monitoring to ensure that requirements for remediation are identified and acted upon in a timely fashion. In this regard, the Board accepts the recommendations of Fort McKay as a reasonable starting point from which to assess Syncrude's current monitoring programs. The Board would expect Syncrude to submit a proposal, including timelines, for improvements to the regional air quality monitoring program before the end of 1994. The Board will also ask Syncrude to conduct a multi-stakeholder process to review its monitoring programs in order to reach a consensus, if possible, on what modifications may be required. The Board is of the view that RAQCC or a similar CASA regional committee might be an appropriate forum in which to conduct this review. The same committee could also serve as a forum to review and analyze future monitoring results from any modified system.

The Board also believes that the process for the renewal of Syncrude's various AEP approvals is an appropriate opportunity to reconsider emission limits should the need arise. The Board is prepared to have ERCB staff assist in such a review of emission limits as necessary. The Board notes the considerable variance in opinions with respect to predicted total sulphate deposition levels and in particular dry deposition. The Board finds that there are definite questions and uncertainties associated with the methodology and results reported by both Syncrude and the interveners. The Board is particularly concerned with the need to use unverified model predictions of sulphur deposition rates after 2 decades of actual sulphur deposition from the emissions of oil sands facilities in the region. The Board does not believe that adequate attention has been placed, particularly by industry, on addressing this question. However, the Board also notes the absence of any compelling evidence with respect to the environmental effects of sulphate deposition in the oil sands region. The Board does believe that significant improvements in monitoring are necessary to help quantify deposition rates, to confirm deposition models, and to develop public confidence. This activity should be actively pursued by Syncrude. The Board will expect Syncrude to seek input from regulatory and other stakeholder groups to develop improved and more widely supported methods for monitoring and predicting sulphate deposition.

The Board notes that exceedances of AEP's air quality objectives have occurred in the past as a result of emissions from both oil sands facilities in the region although significantly fewer exceedances have been attributed to the Syncrude operation. The Board believes that the potential for similar exceedances remains, particularly given the increased levels of emissions associated with Syncrude's proposed operations. The Board therefore expects Syncrude to be increasingly vigilant in its efforts to address issues of ambient air quality, particularly with respect to nuisance impacts such as odours.

Health Impacts

The Board acknowledges the concerns of many of the interveners that atmospheric emissions from the oil sands plants are impacting on the health of the region's population. The Board believes that there is an obligation on industry to address this issue as effectively and rapidly as possible. The Board also acknowledges Syncrude's commitment to support and participate in a regional health study that is broadly based and involves all stakeholders. The Board notes, however, that concerns about the health effects from atmospheric emissions have, despite a number of efforts, continued to exist in the oil sands region as well as other areas of the province. The Board does not support a health study carried out simply for its own sake and expects any health study undertaken in the region to be meaningful, with terms of reference sufficiently broad to demonstrate both short and long term effects.

The Board believes that Syncrude should initiate the planning for such a health study for the oil sands region by acting as a catalyst to bring all the appropriate stakeholders (industry, public, and regulatory) together, in the very near future, to design and undertake a comprehensive study. As suggested at the hearing, such a health study could be integrated with other regional health studies proposed for the area. In order to make the study meaningful, the Board believes all emission sources in the region must be adequately characterized and quantified and would therefore require, as one component of the study, that Syncrude undertake to update its emission data by characterizing significant sources and in particular the diverter stack.

4.2.2 Reclamation

Need for Approval and Jurisdiction

The Board has a mandate to ensure that resource development occurs in a safe, efficient and environmentally sound manner which balances the broad interests of all Albertans. The Board considers reclamation activities to be an integral component of any mineable oil sands development, particularly since reclamation is ongoing throughout the project life. It therefore believes it has the obligation and responsibility to consider, at a conceptual level, reclamation matters when it reviews and approves development proposals such as Syncrude's. The Board believes this responsibility requires that it be satisfied that an operator can successfully reclaim its site in accordance with all established regulatory requirements and objectives. If the Board can be satisfied a project meets all relevant criteria for responsible development, including reclamation, it may then find the project to be in the broad public interest, subject to any conditions it may wish to impose. In the case of reclamation, the Board notes that an approval from the ERCB is intended to address the general concept and approach rather than specific details. The details, the Board believes, are dealt with in the C&R approvals issued by AEP.

Overall Site Reclamation

As described previously, the Board believes its responsibility with regard to site reclamation is to determine whether an operator can successfully reclaim the disturbance associated with its proposed developments. In Syncrude's case the Board is satisfied that Syncrude has demonstrated that it can meet the relevant objectives and requirements to successfully reclaim its site. The Board acknowledges that Syncrude has attempted some reclamation activities which have not been entirely successful, however, it is satisfied that such performance is part of an expected learning process and that, on balance, Syncrude's overall effort has to date demonstrated sufficient progress that it is reasonable to anticipate ultimate success.

The Board does not believe it has an approving role on the matter of the appropriate level of diversity of species in the final reclaimed landscape or the regional integration of other reclamation proposals. In general it believes a diverse ecosystem and regional integration of plans are reasonable objectives, but believes the input of all stakeholders should be sought in making a final determination on these matters. In any event, the Board believes these issues are the responsibility of AEP which has an appropriate process to provide for input from affected stakeholders.

Fine Tails Reclamation

The Board recognizes the reclamation of fine tails to be one of the most significant challenges facing Syncrude in developing an acceptable overall reclamation plan. The Board also recognizes that, because of the enormous volume of fine tails, the method chosen for its reclamation will have considerable impact on Syncrude's overall mine development plans. As such, the Board believes it is both necessary and appropriate to provide some direction to Syncrude on this matter.

The Board notes the considerable research and development work conducted by Syncrude in support of its water-capped fine tails reclamation concept. It is satisfied that the water-capped fine tails concept as proposed, appears to present a relatively low environmental risk and may represent the most cost effective method by which to address the reclamation of fine tails. While the Board finds that the work done to date is sufficient to satisfy it that the concept has a reasonable probability of success, the Board agrees with the interveners that additional development work is required to verify the performance of the technique and to work out some of the specific design parameters for the final lakes. The Board therefore supports the proposal by Syncrude to develop and implement a large scale demonstration lake as one of the means to dispose of fine tails produced from Syncrude's facility. The Board agrees with others that the demonstration must include a comprehensive program of monitoring and scientific investigation that is developed in consultation with all stakeholders to ensure confidence in the validity of the test.

While the Board believes the water-capped fines tails concept is worthy of further testing, it has some concerns regarding the commercial risks associated with the magnitude of the scale-up proposed by Syncrude. The Board recognizes the potential exists that the water-capped fine tails reclamation concept will be shown to be unacceptable by the demonstration lake. To offset this risk, Syncrude has agreed that, if necessary, it would take all appropriate measures to satisfactorily reclaim the demonstration lake and implement a suitable alternative reclamation technique for its remaining fine tails. The Board is satisfied with Syncrude's commitment but also believes that, until the water-capped fine tails reclamation concept is proven to be successful, Syncrude should continue to aggressively investigate alternative fine tails reclamation techniques. The Board is, however, prepared to endorse the development of the full-scale demonstration, known as the 'Base Mine Lake' or some smaller variation thereof.

In considering Syncrude's evidence regarding the recovery of bitumen from fine tails, the Board agrees that no technology currently exists which has been demonstrated to be both technically and economically viable for the recovery of the residual bitumen contained in the Syncrude fine tails. It is therefore prepared to allow the transfer of the volume of fine tails necessary for the demonstration lake without requiring Syncrude to attempt to recover a portion of the bitumen contained in it. The Board would expect that Syncrude continue to maintain an awareness of technologies which might be used for this purpose so that if a viable technology is developed at some point, it could later be considered for use on the remaining volumes of fine tails prior to any final reclamation activities.

4.2.3 Fine Tails Management Alternatives

The Board notes that many of the demonstrated alternative fine tails reclamation techniques are considerably more costly than Syncrude's proposed water-capped lakes technique on a per unit of fine tails basis. It therefore believes that, until such time as the base mine lake has successfully demonstrated the viability of the water-capped lakes technique, it would be prudent to minimize the amount of fine tails produced in order to reduce any additional costs should an alternative reclamation technique be necessary. Therefore, the Board believes it is appropriate to limit the volume of fine tails that would be allowed to accumulate prior to the successful demonstration of Syncrude's preferred reclamation technique.

Although the Board believes a fine tails volume limit is justified, it notes and acknowledges that Syncrude's proposed 'engineered tails' initiative is an appropriate and reasonable first step in addressing the issue of minimizing the volume of fine tails produced. However, the Board would expect Syncrude to continue to aggressively pursue research and development on a range of other techniques which might further reduce both the volume and toxicity of existing or future volumes of fine tails. The Board intends to work with Syncrude to establish a suitable program to further minimize the production of fine tails and to identify appropriate limits.

4.3 Socio-economic Issues

The Board expects that an expansion of this magnitude would confer significant economic benefits on the region in terms of additional employment opportunities, local taxes, and expenditures to businesses located in the Fort McMurray area. Although the Board has not attempted to quantify these anticipated benefits, it appreciates that the economic impacts would be less than originally anticipated in the application that was filed in 1988, as reflected by the overall reduction in capital costs from $4.5 to $2.3 billion. Nonetheless, the project is substantial and would represent significant economic activity.

There is no question in the Board's mind that the development of the Mildred Lake Project has had significant impacts on the native communities in the Fort McMurray region in general and specifically Fort McKay. Some impacts, such as improved employment and business opportunities, might be considered positive while others, such as changes in traditional land uses and economies, could be expected to have significantly strained native social systems.

The Board accepts that the social and economic problems described by the chiefs of the ATC are real and are significant. The question which the Board must address is whether these issues arose due to the presence of Syncrude, and if so, whether there is an onus on Syncrude to address these issues as a component of its new development proposals.

The Board believes that Syncrude has, particularly in recent years, made a sincere and, in general, effective attempt to incorporate a recognition of native needs and concerns into its corporate planning. The Board is not surprised that such planning efforts have, on occasion, been a difficult process for all parties, but overall finds that Syncrude has been conscientious in its efforts.

The Board is not convinced that the negative social impacts experienced by the native communities in the region are fundamentally the result of Syncrude's operations. While the presence of Syncrude may have had some effect on the magnitude of these negative social and economic impacts, the Board does not believe that the presence of Syncrude has been the root cause of the problems affecting these communities. Overall the Board believes that, in fact, the presence of Syncrude and its corporate policies have resulted in a net gain for the region's native communities.

A number of ancillary issues were raised by Fort McKay and the various members of the ATC, including compensation for lost use of traditional lands, uneven treatment of Metis and natives, government funding of the ANDC, and the transfer of tax revenues from ID-18. These issues are clearly not within the mandate of the ERCB and it would not be appropriate for the Board to direct Syncrude to address these concerns. By way of this report, however, the ERCB will ensure that the concerns of Fort McKay and the ATC are communicated to the appropriate provincial government agencies so that they may determine what further action is required.

5 DECISION

Having regard for its responsibilities under the Oil Sands Conservation Act and after careful consideration of all evidence presented at the hearing, the Board makes the following rulings with respect to Syncrude's application:

1. The request to increase the current SCO production limit from 10.0 to 12.6 × 10^6 m^3/yr, including the use of hydrotransport, is approved subject to:
   - Syncrude maintaining atmospheric emissions from its facility at or below existing limits and maintaining flare and diverter emissions below an annual average of 5 t/d of SO_2,
   - Syncrude pursuing appropriate opportunities to further reduce its emissions and reporting on its progress annually, and
   - Syncrude developing ambient air quality, sulphur deposition and biomonitoring programs through consultation with regional stakeholders and periodically reporting to the Board and other stakeholders on the results of these programs to assist in determining if circumstances warrant changes to emission limits for the plant.

2. The request to extend the expansion approval construction start date from 31 December 1994 to 31 December 1997 is approved subject to Syncrude reviewing any significant modifications to the project with Board staff prior to the commencement of construction. The production limit for expansion will be increased to 17.6 × 10^6 m^3/yr.

3. The request to extend the overall project approval expiry date from 31 December 2018 to 31 December 2025 is approved essentially without condition. The approval remains subject to the Board's broad mandate to review and modify any approval issued by it if sufficient justification exists.

4. The request to import or export crude bitumen to or from the Mildred Lake facility is approved.

5. The conceptual mining, lease development and reclamation plans, including the proposed water-capped lakes technique for fine tails reclamation, are endorsed subject to:
   - Syncrude developing the 'base mine lake' with a suitable monitoring program and successfully demonstrating the associated reclamation technique, and
   - Syncrude continuing research and development efforts into alternative reclamation and tailings management technologies.

6. The mine and associated overburden dump west of the McKay River is not approved at this time and will require a separate application to the Board once more definitive plans are in place.

7. The development of the base mine demonstration lake is specifically approved subject to Syncrude developing associated comprehensive monitoring and scientific investigation programs in consultation with its stakeholders.

DATED at Calgary, Alberta on 20 July 1994.

ENERGY RESOURCES CONSERVATION BOARD

RG Evans

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

R. G. Evans, P.Eng.
Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Syncrude Canada Ltd. (Syncrude) F. M. Saville, Q.C. R. A. Neufeld B. J. Roth	A. Hyndman, P. Eng. J. Carbery A. Fair, P.Eng. B. Friesen, P.Eng G. Pool, P. Eng. Dr. J. Clark Dr. K. Nickerson, M.D. Dr. R. Pauls Dr. R. Willes of CanTox Inc. D. Dabbs of Concord Environmental M. Davies of Concord Environmental P. Fellin of Concord Environmental J. Smith of Concord Environmental G. Demke of Foster Research P. Nichols of Nichols Applied Management J. Korol, P.Eng. of Terracon Geotechnique Ltd. L. Nichols, P.Eng., P.Geol. of Terracon Geotechnique Ltd. Dr. N. Morgenstern, P.Eng. of the University of Alberta L. Sawatsky, P.Eng. of W-E-R AGRA Ltd.
Fort McKay First Nation and Fort McKay Metis Local 122 (Fort McKay) J. N. Slavik	Chief J. Boucher A. Boucher C. Boucher L. Courtoreille J. Grandjambe E. Lacorde V. McDonald F. Orr R. Faichney Dr. D. Wallace of the Alberta Research Council D. Andres, P.Eng. of the Alberta Research Council

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Fort McKay First Nation and Fort McKay Metis Local 122 (cont'd)	Dr. A. Legge of Biosphere Solutions J. Green, P.Biol. of The Delta Group Ltd. Dr. D. Taplin, P.Eng. of Komex International Ltd. N. Finlayson of the Land Resources Network Ltd. Dr. D. Herman, Ph.D. of the University of Calgary
Syncrude Environmental Assessment Coalition (SEAC) B. K. O'Ferrall S. Denstedt	R. MacIntosh P. McInnes D. Smith
J. Rogers and Edmonton Friends of the North Environmental Society (EFONES) M. Bronaugh	M. Bronaugh J. Rogers Dr. P. Hessel of the University of Alberta Dr. M. Nyborg of the University of Alberta R. Wilde
Athabasca Tribal Corporation (ATC) J. N. Slavik	Chief T. Mercredi of the Fort Chipewyan First Nation Chief J. Boucher of the Fort McKay First Nation Chief F. Black of the Janvier First Nation S. Courtoreille of the Mikesew First Nation T. Punko K. Shipley
City of Fort McMurray (Fort McMurray) G. Boutilier	Mayor G. Boutilier

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Projects Engineering Contractors Association (EPECA) S. Sanford D. Crowther	M. Propp, P.Eng. of Delta Catalytic Corporation K. McCrae, P.Eng. of Fluor Daniel Canada, Inc. D. Macdonald, P.Eng. of Kilborn Western Inc.
Alberta Environmental Protection (AEP staff) R. Bodnarek L. Brocke N. Chymko S. Gabos R. George W. Macdonald B. MacDonald B. Martel C. Powter S. Rutwind G. Van Nes	
Energy Resources Conservation Board staff T. Abel R. Creasey M. Dmytriw R. Heggie K. Johnston M. Miller B. Purcell J. Sutherland	

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

Decision D 94-6

CONWEST EXPLORATION COMPANY LIMITED Applications No. 931148 & 940446 to 940450

1 INTRODUCTION

1.1 Applications

Conwest Exploration Company Limited (Conwest) submitted the following applications for construction of a new sour gas[1] plant and related pipelines in the Grande Prairie area:

Application No. 931148 relates to the development of a sour gas plant proposed for the south-west quarter of Section 8-75-7 W6M. The plant would be designed to process a maximum of 4226 thousand cubic metres per day (10^3 m^3/d) of raw sour gas, from which 3577 x 10^3 m^3/d of residue gas, 316 m^3/d of liquified petroleum gases (LPG), 475 m^3/d of condensate, and 479.0 tonnes per day (t/d) of sulphur would be recovered on a normal operating basis. Conwest proposes to truck all recovered sulphur in liquid form to an approved sulphur block located near Fox Creek. There would be no sulphur storage on-site under normal circumstances. Sulphur emissions from the facility would be 4.8 t/d at maximum plant capacity based on a normal operating sulphur recovery efficiency of 99.0 per cent. This level of sulphur recovery exceeds provincial standards. Conwest has requested that its approval be based on the required sulphur recovery efficiency of 98.7 per cent which would correspond to a sulphur emission level of 6.2 t/d. A full Environmental Impact Assessment (EIA) was filed with the application pursuant to the Environmental Protection and Enhancement Act. Figure 1 is an overview of the area of interest showing the proposed plant site, alternative plant sites, and other features of interest in the general area.

Applications No. 940446 through 940450 are for related pipelines to gather sour raw gas and sour solution gas to feed the proposed plant, and to transport natural gas liquids and condensate to the Peace Pipe System and fuel gas to each well site. The details are provided in the supporting information filed by Conwest; and Figure 2 shows the proposed pipeline routes. The proposed sour natural gas gathering system would be a Level 2 facility as defined in the Board's Interim Directive ID 81-3[2], which sets out the minimum setback requirements for sour pipelines and facilities.

1.2 The Hearing

The applications were considered concurrently by the Board at a public hearing in Grande Prairie, Alberta on 21, 22, 25, and 26 April 1994 before Board Members F. J. Mink, P.Eng. and N. G. Berndtsson, P.Eng., and Acting Board Member H. O. Lillo, P.Eng. Those who appeared at the hearing are listed in Table 1, together with abbreviations used in this report. Written submissions in support of the application, were received from Anadarko Petroleum of Canada Ltd.

---

[1] Sour gas is natural gas which contains hydrogen sulphide (H_2S).

[2] ERCB Interim Directive ID 81-3: **Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments**, 16 December 1981.

(Anadarko); Night Hawk Vacuum Service Ltd., a local company; and Tracy Horte, a local resident; but they did not appear at the hearing. In addition, Alberta Environmental Protection (AEP) appeared for purposes of cross-examination and argument only.

1.3 Background

Conwest discovered major new, non-associated sour gas reserves in the Montney, Halfway, and Doig formations, in an area extending in a north-westerly direction from the Town of Sexsmith, roughly parallel to the Saddle Hills, toward the Valhalla/LaGlace area. Conwest estimated its share of the reserves to be in the order of some 12 x 10^9 m^3 of gas and natural gas liquids. In addition Conwest has been successful in finding oil in the Valhalla area, and currently has two single-well batteries at which sour solution gas is being flared. Most of Conwest's wells are located on agricultural land designated as the White Area[3]. Its proposed plant site is located on public land, designated as the Green Area[3], and leased for grazing.

Conwest submitted that it currently has 11 wells ready for tie-in to its proposed gathering system and noted that it has an ongoing, active exploration program in the vicinity of the plant. As new wells are drilled and completed, Conwest indicated it would apply separately to the Board to tie-in each well to the gathering system. Conwest anticipated that it would have to drill two wells per year over the estimated 25-year life of the plant in order to maintain gas production from the reservoir. Figure 2 shows the sour gas wells drilled to the date of Conwest's amended application, the oil wells at which Conwest has committed to conserve solution gas by tying in to its proposed plant, and the Green Area/White[3] Area boundary.

As noted in Figure 1, the following sour gas processing plants are found in the general area: (1) the Talisman Teepee Creek plant, (2) the Crestar Wembley plant, (3) the Alberta Energy Company (AEC) Sinclair (Hythe) plant, and (4) the North Canadian Oil (NCO) Progress plant.

Suncor Inc. (Suncor) has also been successful in finding new sour gas reserves in the general area and was considering a separate sour gas processing facility to satisfy its needs. Because of the Board's plant proliferation policy, Conwest and Suncor investigated the possibility of utilizing one plant. In addition, Conwest canvassed other producers in the area to determine their processing needs and to consider conserving other solution gas in the area currently being flared. As a consequence the proposed plant would process gas for Conwest, Suncor, Anadarko, Cimarron Petroleum Ltd., Enron Oil Canada Ltd., Wintershall Canada Ltd., Petrostar Petroleums Inc., Rigel Energy Corporation, Crestar Energy Inc., and Taurus Industries Ltd. The gathering system to bring the main part of Suncor's reserves, located to the south-east of the Conwest reserves east and south-east of Grande Prairie, to the proposed Conwest plant would be the subject of a separate application to the Board.

2 ISSUES

The Board has reviewed all of the evidence respecting the proposed sour gas plant and the related pipelines, and finds it to be technically acceptable. The Board is satisfied that there is a market for the gas and that additional sour gas processing capacity is required in this area. This is based on the size of new sour gas reserves discovered in the area in the past few years, the continuing industry exploration interest in this area, the volume of solution gas currently being flared, the level of utilization of sour processing facilities at the existing four plants, and by the industry interest in the proposed Conwest plant which has been increased in size from Conwest's original plan. The Board notes that none of the interveners questioned the need for the proposed Conwest plant; nor were direct concerns raised with regard to the proposed Conwest pipelines. The Board concludes that there is a need for the applied-for processing plant and related pipelines and that they meet all of the Board's technical regulatory requirements. Because no specific issues were raised regarding the pipeline applications, the Board will not address them any further in this report.

---

[3] The Green and White Areas are defined and shown on the Public Lands General Classification Map, December 1991, which is available through Maps Alberta.

Having regard for the above and upon a review and consideration of the evidence filed at the public hearing, the Board believes the following to be the central issues that it must address in considering these applications:

- the suitability and effectiveness of Conwest's public consultation process,
- the site selection process and the suitability of Conwest's selected site,
- the environmental and other impacts of the proposed sour gas plant, and
- native issues and their relationship to the proposed plant.

3 PUBLIC CONSULTATION

3.1 Views of Conwest

Conwest submitted that it had conducted a thorough and extensive public consultation process that involved several approaches to inform the public of its proposed project and obtain public input. These approaches included mailings to local residents, meetings with individual residents, group meetings, and open houses together with newspaper coverage. Details are included in Appendix A. Conwest also provided tours to existing sour gas plants for interested residents and placed copies of its applications in a number of libraries in the surrounding communities.

In May 1993 Conwest solicited nominations from organizations representing local area interests to form a community advisory committee (Advisory Group) as another means of disseminating information on its proposed project and identifying and receiving input on issues from a broad cross-section of the public. Eight organizations volunteered to participate on the Advisory Group. Representatives from the public were also invited to participate. Ultimately the group consisted of 16 members and all meetings were open to the public. Conwest has indicated that it is committed to continue working with the Advisory Group both during the construction phase and the subsequent operational phase of its project.

Conwest indicated that it had contacted the Band Manager of the Horse Lake Indian Band, the closest Indian Band to its proposed plant site, in early January 1994 and received no formal response or interest in the proposed development.

3.2 Views of the Interveners

The Sexsmith Chamber of Commerce (the Chamber) commented that, in its opinion, it was unfortunate that the Carter Group could not have worked with the Advisory Group because if the concern were great enough it may have been able to influence Conwest to change its site. The Chamber indicated that when people in a community have concerns with a project, they have a greater opportunity to influence the outcome through the public consultation/public advisory process than through the public hearing process.

Members of the Advisory Group indicated that all meetings were open to anyone who was interested. One member, Mr. D. Kirkham, noted that the Advisory Group had discussed how to get as many people as possible to participate in the process. In his opinion Conwest could not have done anything more to increase public participation.

The Carter Group indicated that it was better off not getting directly involved in the public consultation process. In its view, Conwest's public consultation was nothing more than an attempt to get people on side with Conwest and was more of a public relations exercise than a public consultation exercise. The Carter group also indicated that, although it did not participate directly in the Advisory Group, it could and did voice its concerns to members of the Advisory Group.

The Carter Group was suspicious about the motives and tactics of Conwest and the role of the Advisory Group. It noted that persons participating in the Advisory Group, by the act of participating, appeared to some to be endorsing the Conwest project.

The Lesser Slave Lake Indian Regional Council (Indian Council) is comprised of Chiefs of nine of the Indian Bands under Treaty 8. The Horse Lake Indian Band, a member of the Indian Council, is the closest to the Conwest proposed site and is located approximately 40 kilometres (km) west of the proposed site.

The Indian Council argued that it had not been contacted in the early part of the public consultation process or asked to participate in the advisory group. It stated that advertising a project in the usual newspapers would not be seen by the native community and it suggested a better approach would be to advertise in the native newspapers such as the "Windspeaker".

The Indian Council indicated it had no record or recollection of the offer by Conwest to consult with the Horse Lake Band on Conwest's project. It confirmed that the mandate of a Band Manager is limited and suggested in future notice of projects should be sent directly to the Grand Chief of the Indian Council to ensure that the right person receives the notification. In addition, the Indian Council indicated that the Board should require all project proponents to consult with native peoples in respect to any proposed development which may affect their lands or lands with outstanding land claims. The Indian Council claimed there currently is no effective way to bring projects such as this to its attention.

3.3 Views of the Board

The Board has long encouraged communication between an energy development project proponent and interested parties who may be affected by such a project. The Board believes that direct consultation with affected parties benefits everyone during the planning, construction and operating phases of a project. Such consultation allows for the proponent to address public concerns early in the planning process when it is usually easiest to effect project changes. The public has the opportunity to learn about the project and have its questions answered, to advise the proponent of any concerns it might have, and to just generally be in a better position to make informed decisions. In the Board's view, there is opportunity for a win-win situation for everybody. Such a process should not preclude people from raising issues of concern or taking exception to the response by the applicant. It would also not preclude anyone who participates in the process from objecting to the final application.

The Board believes that all parties who may be directly impacted by a proposed project should be notified about that project and be provided with the opportunity to have their concerns and questions addressed early in the planning stage. While the public consultation process has been found to be effective in allowing affected parties to become aware of energy development projects, in cases where the Board believes there may be a concern or for large sour gas plants where the impact may be considered great, it generally advertises for objections as part of its normal approval process; and it did so for the Conwest applications. The Board has never intended that early public consultation would exclude anyone from its process, and it finds no compelling evidence that Conwest attempted to isolate or exclude individuals or groups in this case.

With respect to the Carter Group, the Board accepts the position that it was the Carter Group's prerogative not to directly participate in the Advisory Group process.

The Board is satisfied that Conwest did make a reasonable effort to brief the nearest Indian Band, the Horse Lake Band, about its project. The letter to the Band Manager should have been sufficient to bring this project to the Band's attention, and Conwest's open invitation to discuss the project should have provided sufficient time for the Band to learn about the project and to raise its questions and concerns.

The Board believes that Conwest met its requirements with regard to public consultation. It also notes the significant value that the Advisory Group added to the project through the changes that Conwest made to the project as a result of the Advisory Group's input. The Board believes that overall, the Conwest process achieved the broad objectives to apprise the parties affected by its proposal and to respond to their concerns.

4 SITE SELECTION

4.1 Conwest's Site Selection Process

4.1.1 Views of Conwest

Conwest stated that the goal of any site selection study is to find a site that is acceptable from an environmental, technical, and sustainable economic perspective. An acceptable site represents a balance of all these factors. It indicated that it had undertaken a comprehensive site selection study, which included the development of acceptable siting criteria for each of the above perspectives, mapping and field investigation of baseline data in the planning area, identification of potential sites having favourable characteristics, and detailed evaluations of these potential sites. In addition, Conwest indicated that it met early in the process with various provincial and local government officials to obtain their input on sites.

As a first step, Conwest established the following general siting criteria to assist in a preliminary identification of potential sites that might be suitable for a sour gas plant:

- consistency with government regulations and local County or Regional plans and bylaws,
- proximity to the raw gas source and product delivery points,
- avoidance of proliferation of facilities,
- obtaining public input,

- proximity to existing industrial land use,
- avoidance of populated and sensitive natural areas, and
- proximity to existing road access.

From an initial 18 potential sites, it selected 11 for detailed environmental study. These 11 sites are shown on Figures 1 and 2. Conwest indicated that the seven sites were eliminated due to factors such as proximity to residences, strong landowner disapproval, high wildlife values, unfavourable terrain features, and the need to avoid large economic costs without major public benefits.

Conwest conducted a detailed site inventory for each of the 11 sites with regard to operational constraints and opportunities, land use, visual impact, air dispersion characteristics, geotechnical constraints/terrain, hydrological characteristics, floral and faunal characteristics, and historical resources. The principal environmental parameters considered were potential impacts from proximity to the nearest residence and locating in areas of low population, minimizing land-use conflicts and land disturbances, and optimizing use of existing infrastructure, aesthetic impacts, air quality, hydrology, fisheries and wildlife, vegetation and biodiversity, and historical resources. Cost-benefit considerations in the site selection process included the proximity to gas reserves and product tie-in points, the proximity to high grade road access, the proximity to public facilities and residents, air quality, soil and topography, hydrogeology, vegetation, fish and wildlife, biodiversity, historical resources, economics, and engineering considerations.

Conwest stated that site selection is a complex, multi-disciplinary process that is on-going, interactive, and evolutionary. It emphasized that it involved a balancing of the environmental, economic, technical, and social areas; and contended that value judgements had to be made in selecting a final site. Conwest disagreed with the Carter Group's assertion that environmental consultants given an assignment by a project proponent, to select the best site, should do that assignment in total isolation from other factors. In its view a project proponent must be able to factor in all considerations.

4.1.2 Views of the Interveners

The County of Grande Prairie (the County) indicated that its main site selection concerns centred on the impact of traffic and dust on residents, the cost to the County of any required infrastructure and it especially noted road upgrading costs as an example, and minimizing industrial impact on farmland. The County pointed out that all of its planning documents and bylaws are aimed at protecting agricultural land; and it indicated that it had suggested to Conwest consideration of a site near the County Landfill to address the above concerns.

Mr. Kirkham stated that, as a resident of the community, he would be very much against moving the proposed plant to an existing plant site because of the distance required to pipeline high pressure sour gas. In his view there would be more danger associated with such a pipeline than with the proposed plant itself.

The Town of Sexsmith indicated its main site-related concern was the loss of good farmland, and that it liked the preferred site because it would minimize any loss.

The Carter Group emphasized that its concern is over the preferred location of the proposed plant in the Saddle Hills. It contended that Conwest's site selection process was flawed, and that Conwest should have given more consideration to other sites, especially those sites where there is already an existing plant; which would be in accordance with the Board's policy on plant proliferation. The Carter Group contended that Conwest had rejected the existing plant sites too easily and that certain advantages associated with these sites had been dismissed out of-hand because Conwest wanted to build its own plant. In the Carter Group's view, Conwest had made up its mind on Site 8, the proposed plant site, from the very beginning and it was not prepared to consider another site even when the results of the environmental assessment were suggesting that another site was better. As a further example of the bias it perceived Conwest had for Site 8, the Carter Group pointed out that even though the preliminary geotechnical assessment for this site was poor, it went ahead and conducted a hydrogeological study when it did not do so for any other site.

The Carter Group stated that it viewed the whole EIA as a "kind of quickie exercise" that had been rushed through and was deficient in certain aspects. The main deficiency from its point of view was that the weighting applied to the various environmental factors was not clearly set out. The Carter Group contended that, because the environmental consultants had worked with Conwest on the EIA, Conwest had influenced the content of the EIA to some degree, and therefore the EIA was not a totally independent report. In its view, the environmental consultants should have been allowed to do their work and prepare their reports independently of any input from Conwest.

4.1.3 Views of the Board

The Board agrees with Conwest that site selection is a balance of environmental, technical, economic, and social factors. In balancing these factors there are usually trade-offs involved in reaching a final site selection. The Board has reviewed Conwest's general approach to site selection as well as its specific methodology. It finds Conwest's approach to be reasonable and, in the Board's opinion, Conwest's overall site selection process was both comprehensive and complete.

The Board notes that early preference by Conwest for the preferred site in its discussion with the public was problematic. However, the Board does not agree with the Carter Group that Conwest's ultimate site selection process was flawed. On the contrary, the Board finds it to have been conducted in a very thorough manner. The Board does not believe it unreasonable for a project proponent to identify sites that appear to meet broad public interest tests, as long as that proponent conducts a fair and thorough assessment of the potential sites. It is also expected that the detailed review should be able to confirm the original preferences or be sufficiently convincing that a better site exists. The Board believes that Conwest's work has met those objectives.

4.2 Suitability of Conwest's Preferred Site (Site 8)

4.2.1 Views of Conwest

Conwest investigated the options for processing its gas at one of the four existing sour gas plants in the area as shown in Figure 1. However, because these plants had been designed to process sour gas containing a lower percentage of H_2S (from 0.7 per cent to 3.5 per cent), they are not capable of processing Conwest's gas with its higher H_2S content (overall average of 8.3 per cent). To use an existing plant site, Conwest concluded that it would have to build a new plant 2 to 5 times larger than the existing plants on a gas-inlet basis, adjacent to an existing plant. This option was not desirable because of a combination of close proximity to residents, distance from the gas pool, lack of suitable available space at the sites, and the need for a second field processing facility.

Conwest proposed to transport the produced wet gas directly to the processing plant without field separation and dehydration. It stated that using one of the existing plant sites would require a separate field processing facility to gather the gas at a central location, separate the liquids, dehydrate, and compress the sour gas for delivery to that plant because of the difficulty in transporting large quantities of wet gas over the longer distances. Conwest indicated that a field processing facility would have to be located in the vicinity of the proposed plant for transportation to either the AEC Sinclair (Hythe) or the NCO Progress plants, or about 11 km south-east of the proposed site if the gas were to be transported to either the Crestar Wembley or the Talisman Teepee Creek plant. In its view, such a field processing plant would approach the scale of and require the infrastructure of the proposed plant. In essence it said that remote processing would lead to two significant facilities to handle the gas, one centrally located in the field and the other adjacent to the remote sites at existing plants. This additional facility would add considerably to the cost of the project without noticeable environmental benefits; in fact the longer pipelines required would result in greater disturbances to the land. Conwest acknowledged that Suncor might have to provide some field facilities to dehydrate its raw gas for transport to the proposed location; and that also some field compression either now or in the near future would be necessary.

Conwest concluded that constructing its plant adjacent to an existing plant was not feasible because it would result in unnecessary field facilities, would incur higher capital costs, and such a scheme would impact on a much greater number of people in the County.

Conwest disagreed with the Carter Group's contention that an advantage of using the Talisman Teepee Creek plant site was that it was already serviced by product lines and a NOVA sales gas line. It pointed out that the existing NOVA line is sized for the capacity of the Teepee Creek plant which is significantly smaller than Conwest's needs. This line would have to be looped or a new lateral built to handle Conwest's gas volumes.

Conwest indicated that it prepared detailed environmental studies and comparisons of all 11 selected sites, and that the 3 sites in the vicinity of the County Sanitary Landfill (Sites 7, 8, and 9) appeared to be the best sites on balance. These sites were already disturbed. Site 9 is in the White Area, partially under cultivation, and has a well on it. Sites 7 and 8 are located along the fringe of the Saddle Hills, on Crown land covered by a grazing lease. Site 8 also is a registered trapping area.

These sites either are fenced or have been fenced in the past and can be refenced in future. Highway 724, which is scheduled to be upgraded to a secondary highway standard, borders all three sites. Conwest concluded that these sites are already seeing a tremendous amount of human activity, in particular, road traffic and recreational use, and the disturbance factor attributable to the proposed plant would not increase significantly especially with regard to Site 8. Conwest noted that both the County and the majority of the residents favoured a site in the vicinity of the County Landfill.

Conwest recognized that the results of the environmental evaluation and comparison of the 11 sites showed that Site 6 ranked the highest, but noted that all sites were close in ranking. Sites 7, 8, and 9 all demonstrated favourable environmental characteristics. Conwest presented evidence indicating a relatively thin layer of till overlying the bedrock at Site 6 compared to its preferred site (Site 8) which had a significantly thicker till layer. A thinner till thickness would provide less natural protection for the groundwater in the event of an accidental spill. It also noted the latest hydrogeological study at Site 8 confirmed that the groundwater conditions were suitable for industrial use.

When Conwest considered the economics, it found Site 6 to be the most costly and Sites 7, 8, and 9 to have the lowest cost. It noted the principal reason for this was the cost to upgrade the road to access the site whereas Highway 724, which runs by the preferred site, was to be upgraded to secondary highway status on a cost-shared basis between the County and the province. Conwest submitted that it selected Site 8 to build the plant because there are fewer people living adjacent to it, because of the preference of the surface grazing leaseholder, and because in its view it demonstrated the best combination of environmental, economic, and technical and social features.

Conwest took exception to the Carter Group's contention that it had decided on Site 8, the proposed site, from the very beginning, and that it would have stayed with Site 8 no matter what the results of the selection process and EIA were. Conwest submitted that Site 8 had not been its first choice; but that it had started initially with three other sites in mind, all of which had been shown on the map used for its original public consultation meetings. It indicated that it was because of the preference that it found in the majority of the community and by the County itself, for a site in the vicinity of the County Sanitary Landfill, that Conwest keyed in on this area for detailed investigation. Conwest stated that, if a site other than its preferred Site 8 had shown much superior environmental and economic merits, it would have selected that site.

4.2.2 Views of the Interveners

The County indicated that it had suggested that Conwest consider a site along secondary Highway 724 in the vicinity of the County Landfill site, and that it supported the preferred site as the best from the County's point of view. The County also confirmed that it plans to upgrade Highway 724 in the near future and that the costs would be shared between the County and the province.

The Carter Group indicated that it had not undertaken any study of its own to determine the best location for the proposed plant and it did not advocate any particular site. However, it highlighted what it saw as some of the advantages of two of the sites over Conwest's selected site as well as some of the disadvantages it saw in Conwest's selected site. For Site 1, the site of the existing Talisman Teepee Creek plant, the Carter Group noted that there was land available, a paved highway ran nearby, the site was already serviced by a NOVA line and products pipelines, and that the presence of the existing plant already imposed an industrial impact on the area and the local residents. It also noted that the county had already issued a development permit for an ethanol plant to be located across the highway from the Teepee Creek gas plant in spite of the County's policy to protect agricultural land.

The Carter Group noted that Site 6 was the best site from an environmental point of view based on Conwest's own studies and that the estimated upgrade cost of the road access to Site 6 was less than the cost to upgrade Highway 724 which runs adjacent to the preferred Site 8. With respect to Site 8, the Carter Group noted that Highway 724, which runs adjacent to the proposed plant site, in its understanding while designated a secondary highway, was in fact little more than a small gravel road going over a hill and would not be upgraded until, or if, the proposed plant were built. It also pointed out that the proposed plant site was not adjacent to the County Landfill, as Conwest had claimed, but was located about 1 km from it. It pointed out that the tax and other benefits that would accrue to the County would still occur as long as the proposed plant was located somewhere in the County. The Carter Group contended that the County had not considered sites other than Site 8 and that because it had a monetary interest in the matter (in terms of tax revenue), the site selection should have been looked at by an independent party. Overall the Carter Group indicated that Conwest had not justified why its proposed plant should go into the Saddle Hills. In summary the Carter Group indicated that, given the flaws in the site selection process and that its members did not have the expertise to determine the best plant location, the Board should decide where the plant should go.

The Carter Group also stated that the Suncor gathering system or other producers that are going to feed the plant, are not part of this application. In its view, the applicant should present a complete application which would include all producers feeding the plant. This it indicated is important information for determining the most suitable plant location given Conwest's argument about preferring a location which is central to its gas field. In its view, the application is incomplete and the Board should not proceed with its consideration of this application, especially when Conwest is using the fact that Site 8 is at or near the centre of its field, when it is not at the centre of all the fields supplying the proposed plant.

4.2.3 Views of the Board

The Board does not agree with the Carter Group's assertion that Conwest's application is incomplete because the gathering system for the Suncor gas is not part of the application. In the Board's view, the Conwest application is complete and presents sufficient information for the Board to reach a decision on the need for a new plant and its location. Conwest's application indicates that the most suitable location for an independent plant to process Suncor's reserves, from a proximity standpoint to Suncor's solution and non-associated gas wells, would be in the centre of an agricultural area closer to Grande Prairie. Information submitted at the hearing confirmed the location of Suncor's solution gas reserves adjacent to those of Conwest and its non-associated gas reserves to the south-east of Conwest's non-associated gas reserves. As noted in section 2, Suncor must submit a separate application to the Board for its gathering system.

The Board recognizes that site selection for industrial facilities in a rural setting is a difficult challenge. The Board's policy on plant proliferation, given in Informational Letter IL 91-1[4], is intended to ensure that industrial intrusions are reduced and an applicant for a new plant has vigorously explored all reasonable options to use existing gas processing plants in an area should circumstances warrant. It is not intended to totally preclude building a new plant in a broad area where an existing plant or plants are located. The Board appreciates that there can be many factors that could make a new plant preferable to using an existing one, but each case must be evaluated on its own merits. In this case, the Board believes that it would be appropriate to review the potential of using the four existing plants in the area. These plants were noted in Section 1.3 and are shown on Figure 1.

The Board reviewed in detail the environmental, economics, technical and social evidence presented on both the existing plant sites and the potential new sites. The Board found that Conwest's site selection to be thorough.

The Board notes that the Conwest sour gas contains considerably more H_2S than the sour gas being processed at the existing plants. As currently designed, none of the existing plants have the technical capability or spare capacity for processing the Conwest gas without process modification and significant expansion. The Board also notes from Conwest's evidence that three of the plants, Talisman Teepee Creek, Crestar Wembley, and NCO Progress are each considering small expansions in the near term and all four plants expect a high rate of utilization over the near term. The Board is aware that this area of the province (the Peace River Arch) is under active exploration. It accepts Conwest's view that considerable reserves remain to be discovered in the area. The Board believes that existing facilities offer limited or no practical opportunity to deal with the reserves to be processed in the proposed new plant. In the Board's view, additional processing capacity is required in the area and a new plant is required.

---

[4] Informational Letter IL 91-1: **Applications for Approval of Gas Processing Schemes-Policy on Plant Proliferation,** 29 January 1991.

The Board sees advantages to locating the proposed plant adjacent to an existing plant, if suitable land is available, and if incremental impacts on the environment and on the local residents who live in the vicinity of the existing plant are sufficiently small or can be adequately mitigated. The Board also recognizes that transportation of sour gas over long distances represents an economic and social cost that must be considered in a siting decision. The Board notes that constructing a plant the size of Conwest's proposed plant would constitute a substantial expansion to what exists at the current plant sites. The sulphur inlet alone would be from 2 to 19 times the existing rates while the total gas inlet would have to be increased from 2 to 5 times. If existing plant sites were used, Conwest would immediately have to construct a separate field facility, located centrally to the wells in its pools to gather, dehydrate, and compress the raw sour gas for delivery to the processing plant. Given the circumstances the Board is in agreement with Conwest that such a facility would occupy an area similar to that of the proposed plant and could have a separate impact as significant as the proposed plant. The Board believes the chief reasons for locating a new plant adjacent to an existing plant would be to minimize the total impact of the new plant and associated pipelines on non-industrial lands, and to take advantage of existing infrastructure (roads, power, NOVA sales gas line, liquid product lines, etc.). The Board must be concerned with the total impact of a project; and in this case, locating Conwest's proposed plant at an existing plant site will not reduce the impact due to the immediate need for the central field facility. In addition, the relatively high residential density around three of these plants would, in the Board's view, make it very difficult for Conwest to mitigate for undue environmental impacts from a much larger plant especially those impacts on residents such as noise. The Board does not accept the Carter Group's argument and implication that the people living near an existing plant, are already impacted by virtue of a plant already being there. The Board considers the NCO Progress plant, from a residential impact point of view, as the most promising of the four existing plants to locate the Conwest plant. However, it considers that plant site too remote. In the Board's view, its location deep in the Green Area in a Key Wildlife Area and longer pipelines would cause some impact on wildlife and there would also be a greater potential for impact from trucking the produced sulphur a greater distance.

The studies and comparisons show that all sites offer some advantages and disadvantages. Because no one ideal site was found, the Board accepts that some trade-offs are necessary. Existing plant sites are not suitable for the proposed plant for reasons already discussed. The Board concurs with the analysis and overall ranking of the sites by Conwest and finds that reasonable and acceptable trade-offs are best offered by sites near the County Landfill. Further, even though Site 8 is marginally less attractive environmentally than other sites, it has considerably more advantage than others in terms of road access, overall cost, and residential impact. The Board notes that some field processing facilities may be required to bring Suncor's gas to the proposed plant site. The Board also expects that in the later life of any gathering system some field compression will be required as the gas pools are depleted. However, the more central location of Site 8 will minimize the need for field facilities now and in the future. In summary, the Board finds overall Site 8 to be suitable provided that the enviornmental impacts to be addressed in section 5 are acceptable.

5 IMPACT OF CONWEST'S PROPOSED PLANT

5.1 Views of Conwest

Conwest carried out a detailed EIA to determine the affect of its proposed plant on the area as required under the new Environmental Protection and Enhancement Act.

Air Quality

Conwest submitted that its revised process design would accommodate the presence of mercaptans[5] which are found in its gas; and that this change reduced the sulphur recovery efficiency from an initial design of 99.2 per cent to 99.0 per cent. Notwithstanding this reduction, Conwest pointed out that the overall sulphur recovery is greater than the 98.7 per cent determined from the Sulphur Recovery Guidelines for a plant of this size.

Conwest contended that the plant would reduce the overall sulphur emissions in the region over the long term. Gathering and conserving the solution gas which is currently being flared at oil batteries in the area, would reduce sulphur emissions by about 6.0 t/d. An additional 4.0 t/d of sulphur from flared solution gas would be conserved by the time of plant startup. The maximum daily sulphur emissions from the plant during normal operations is expected to be 4.8 t/d.

Conwest submitted that its emissions modelling results showed that the sulphur dioxide (SO_2) and nitrogen dioxide ground level concentrations would meet the Provincial air quality objectives. It indicated that its SO_2 modelling included other regional sources which would make only a very minor contribution to the maximum ground-level concentrations.

Soils

Conwest indicated that the soils surrounding its proposed plant site are of low to medium sensitivity to acidification. It submitted that its modelling indicated no measurable change in soil pH levels over a 30-year period, and only about 0.3 to 0.6 pH units over 100 years at the highest deposition rates.

Surface Water and Groundwater

Conwest indicated two major sources of groundwater contamination, the sulphur block and the plant's sanitary landfill had been eliminated. It pointed out that the proposed site has approximately 22 metres of dense, low permeability clay overlying the bedrock, which would provide natural groundwater protection in the event that an accidental discharge or spill were to occur.

Conwest stated that, from a hydrogeological point of view, the risk of its facility causing major groundwater contamination at the proposed site, is very low. Conwest also noted that it would conduct baseline water-well monitoring on all wells within a 3-km radius of the site, and that it would monitor groundwater in the vicinity of the proposed plant site in a manner approved by Alberta Environmental Protection (AEP).

Wildlife and Vegetation

Conwest submitted that the area of land disturbance is about 8 hectares (ha) resulting from the plant and approximately 10 net ha in the forested area resulting from pipelines. It noted that most of the gathering system is on agricultural land and the direct impact of the portion which does pass through the forested portions would be minimized by using existing seismic lines where possible. Conwest indicated that the direct impact is very small when compared to the total Saddle Hills forested area. Conwest also indicated that it would not expect an increase in vehicular access to the Saddle Hills area because it would be using existing seismic lines as much as possible and any new roads required would have access controlled.

---

[5] Mercaptans are odourous sulphur-containing compounds sometimes found in raw natural gas.

Conwest submitted that the plant site is located just inside a Wildlife Key Area which is an area designated as holding some wildlife value but for which a variety of uses are still deemed compatible including logging, oil and gas industry activity, and road development. The proposed site is part of a grazing lease used for cattle in the past and for which the leaseholder could refence and use again in future. Conwest noted that the proposed site is also located near an existing industrial site, the County Landfill, and that the habitat is already fragmented by two roads. Conwest submitted that the disturbance caused by extra road traffic would not be significantly greater.

Noise

Conwest indicated that it would meet the Board's Noise Guidelines as outlined in ID 92-2[6] it noted that it had incorporated various features into its plant design to help achieve this, including the use of electrically driven compressors and pumps, variable speed cooler fans, and housing most process equipment in buildings designed to reduce noise. Conwest intends to review the performance of its plant and, if necessary, revise its operation to ensure compliance with ID 92-2.

Monitoring

Conwest submitted that it had already set up two air quality and weather monitoring stations to provide baseline data on existing conditions in the area. It stated that it is committed to ongoing air quality monitoring in the area and to work with residents, AEP, and others in developing an appropriate program. Conwest also stated that it has committed to wildlife, vegetation, and soils monitoring and would make this information available to the public.

5.2 Views of the Interveners

The primary concern of the interveners with the proposed plant was the general impact that it would have on the Saddle Hills area. In particular the effects on air quality, soils, vegetation (including agricultural crops and native Indian herbal plants), and wildlife were identified. Interveners contended that the regional and cumulative environmental effects assessment was inadequate. Concerns were also raised with groundwater contamination at existing sour gas plants in the province and with the potential for groundwater contamination at Conwest's proposed site.

Some concern was expressed about the sulphur recovery level of the plant. The Peace Country Agricultural Protection Association (the Association) expressed concern that ozone concentrations in the area may exist, and that additional amounts could be generated by volatile organic compounds (VOCs) from the Conwest plant. The Association also raised the question that some soils in the area were already acidic and farmers were already applying lime to their soils to counteract this. It submitted that the additional acid deposition from this plant would result in a reduction of the buffering capacity of the soil thus decreasing its value.

In its questioning of Conwest the Indian Council raised concerns about the potential for increased access to the Saddle Hills due to the proposed plant and pipelines. In addition, the Indian Council indicated that regional air monitoring should be made a condition of any approval that the Board issues to Conwest and that it should be involved with this program.

---

[6] ERCB Interim Directive ID 92-2: **Noise Control Directive**, 24 April 1992.

5.3 Views of the Board

The Board found the Conwest environmental assessment to be detailed and thorough. The evidence shows the proposed plant would operate well within provincial environmental standards and Conwest's commitments should mitigate or minimize any adverse impacts. Given the evidence, the Board does not accept the contention of the interveners that the site proposed for the plant is unsuitable. Because of Site 8's proximity to the County Landfill site and Highway 724, and given the fact that the current site is leased for grazing, the Board believes that Site 8 would have a minimum amount of intrusion on the Saddle Hills and insufficient impact to change the character of the Saddle Hills. While some amount of wildlife impact is expected, the Board does not believe it is serious.

The Board notes that the new plant will result in a net reduction in sulphur emissions due to the conservation of sour solution gas and that this will result in an improvement in air quality especially in the vicinity of existing batteries. Given the level of emissions, the buffering capacity of the soils in the area, and the high pH and buffering capacity of the surface waters, the Board is satisfied there will not be a significant impact on the soils due to acid deposition resulting from the emissions at Conwest's proposed plant.

The Board believes that Conwest's proposed measures for protecting the groundwater, which includes a groundwater monitoring program and leachate detection system, represent good engineering practice and will help to prevent a spill or accidental discharge from occurring and allow for early detection should a leak occur. The Board concurs with Conwest that the potential for major groundwater contamination from this facility is very low.

The Board notes that Conwest's proposed site is located just into a Wildlife Key Area on the edge of the Saddle Hills, adjacent to Highway 724 and in the vicinity of the County Landfill site. Recognizing the current access, the proposed development would not provide any additional vehicular access to the Saddle Hills area and, therefore, not create any additional impact.

The Board notes that the main impact on vegetation is the new disturbance of some 8 ha for the plant site and approximately 10 net ha of forested land for wellsite and pipeline development. Considering the emissions modelling and soils testing results and given that there would not be an increase in access to forested area, the Board does not believe there will be any significant impacts on vegetation or wildlife from plant emissions. It also believes that any environmental impact from accidental releases can be mitigated. The Board concludes the impact of the Conwest plant on vegetation would be minimal.

The Board is satisfied that the proposed plant would be designed to meet ERCB noise guidelines. It notes that Conwest intends to review the plant's performance once its plant is in operation to ensure compliance with the Board's noise guidelines. The Board concludes that the impact on residents would be acceptable.

The Board notes the concerns raised by the Association that high levels of ozone may exist in the Grande Prairie area and that there is a potential for VOCs to increase those levels. The Board also notes that Conwest has indicated that it would be prepared to initiate and participate in a regional airshed monitoring program with others. It would encourage Conwest to proceed with this initiative to quantify the regional air quality and changes to it over time.

Having regard for its conclusions discussed above, the Board finds the proposed site to be suitable and acceptable.

6 NATIVE ISSUES

6.1 Views of Conwest

Conwest stated that this is not a forum to decide issues on treaty rights and rights under the Natural Resources Transfer Agreement. Conwest acknowledged that the native people have a right to hunt, fish, and gather but in its view this constituted an opportunity to do so and not a guarantee. Conwest stated that its proposed plant would not impact on these rights.

6.2 Views of the Indian Council

The Indian Council indicated that project approvals by the Board, over time, may lead to the extinguishment of their 1899 Treaty 8 right to hunt and fish. The Indian Council stressed that the public interest includes ensuring that the obligations by the province to protect the hunting, fishing, and trapping rights of native people are upheld. It indicated that its treaty and aboriginal rights included the right to hunt, fish, and gather on unoccupied Crown land as affirmed in the Alberta Natural Resources Transfer Act of 1930. It argued that the province must protect the integrity of the environment so that the subject matter of these rights is preserved.

In the Indian Council's view the public interest includes ensuring that the native people are fully informed and consulted regarding any developments which may potentially affect their treaty rights and their lands before such projects and developments are allowed to proceed.

The Indian Council stated that it has no interests that conflict with Conwest's leases on the proposed plant site, pipelines, and well sites at this time; and more specifically the Indian Council has no specific claims on these lands.

The Indian Council requested that it be given direct notice of all Board hearings and proposed developments which impact upon its treaty area, that the Board require that all proponents consult with the native people for projects which may impact on their lands including land claims, and that the Board recognize its treaty and constitutional rights in the Board's decision-making process.

The Indian Council requested, with respect to the proposed project, that any approvals given by this Board be made conditional upon the implementation of a regional air monitoring program which includes participation by the Indian Council.

6.3 Views of the Board

The Board notes that the Indian Council has indicated there are no specific claims on the lands where the wells, pipelines, and the proposed gas plant are to be located. The Board does not believe treaty rights or land claims are within its jurisdiction.

As to the Indian Council's request that it be given direct notice of all Board hearings and developments which impact upon its treaty area, the Board reiterates comments made previously in section 3.3, that it was satisfied with the steps Conwest took in an effort to ensure the nearest Indian Band was notified. The Board will continue its policy of giving direct notice to any party that it becomes aware of as a party that may be directly and adversely affected by an application under consideration. Part of this is accomplished through some major newspapers and some local newspapers along with mailouts to known parties in the local area of the application.

7 DECISION

The Board has carefully considered all of the evidence and is satisfied that the proposed sour gas plant and related pipelines are in the public interest and would meet or exceed all existing regulations and requirements that are established to ensure public health, safety, and the protection of the natural environment. In addition,the Board notes Conwest's commitment to continue with ongoing public consultation with affected parties both during the plant construction phase and thereafter during the operational phase. The Board accepts Conwest's undertaking to maintain an extensive program of monitoring with respect to air quality, soils, groundwater, vegetation and wildlife; as well as to be involved with others in a regional airshed monitoring program. Therefore, the Board is prepared to issue an approval for the applied-for sour gas plant and, subject to the approval of the Minister of Environmental Protection, permits to construct the pipelines detailed in the five pipeline applications.

The Board supports the continuation of the Public Advisory Group. It believes such groups offer a good forum for the public to raise issues and for Conwest to address their concerns during the construction and operational phases of the facility.

DATED at Calgary, Alberta on 12 August 1994.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P. Eng.*
Vice-Chairman

N. G. Berndtsson, P. Eng.
Board Member

H.O. Lillo

H. O. Lillo, P. Eng.
Acting Board Member

---

* Mr. Mink was unavailable for signature but concurs with the contents and with the issuing of this report.

Appendix A of ERCB Decision Report D 94-6
Conwest Public Consultation Process For the Proposed Gas Plant

Conwest started meetings with individuals in March 1993. It initially met with local area residents within a 1-km radius of the initial proposed plant sites to explain who Conwest was, to provide information, and to solicit comments on its proposed project and sour gas processing in general. Residents were advised to contact Conwest if they had any questions or comments on the material distributed. Of the 300 information packages sent out, Conwest received two comment cards requesting more information.

In addition to individual meetings, Conwest contacted eight non-governmental organizations in the area in late April and May 1993 to ask for comments on its proposed project. These included the Bear Lakes Surface Rights Society, County West Environmental Society, Ducks Unlimited, Peace Country Agricultural Protection Association, Peace Parkland Naturalists, Sexsmith and Area Environmental Committee, South Peace Environmental Association, and the South Peace Fish and Game Association. Conwest also contacted Allan Johnstone, Dave Ridgeway, and Jim Nelson, three local environmentalists.

A number of meetings were also held between March and June 1993 with the County of Grande Prairie, the Town of Sexsmith, Alberta Environmental Protection, Alberta Occupational Health and Safety, and the MLA for the area to brief officials on its proposed project.

In June 1993 Conwest held or participated in a number of public meetings at which it provided information on its proposed project. A local resident hosted a "Neighbourhood Coffee Meeting" in his home on two different occasions. It took part in the Sexsmith Enviro-Week held at the Sexsmith school and also met with students from the Power Engineering Program at the Grande Prairie Community College. Conwest hosted five open houses held at the Buffalo Lake Hall, the Sexsmith Civic Centre, and the Woking Community Centre and participated in a Crestar Energy open house in Blooming Valley over the period from June 1993 through to January 1994. All were extensively advertised through a mail-out to residents and all were fairly well attended.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Conwest Exploration Company Limited (Conwest) P. J. McIntyre R. B. Brander, P.Eng. K. J. Woldum, P.Eng.	A. M. Johnston, R.E.T. J. W. Stephure, P.Eng. M. B. Schroeder, M.Sc. of Jacques Whitford Environmental Limited C. Dufour, P.Ag. of Jim Lore and Associates Ltd. G. C. Mott, B.Sc. of G.C. Mott Associates R. D. Glaholt, P.Biol. of Tera Environmental Consultants (Alta.) Ltd. P.H.R. Fothergill, M.E.Des. of Tera Environmental Consultants (Alta.) Ltd. T. L. Dabrowski, Ph.D., P.Eng. of Komex International Ltd. L. S. Lyness, P.Geol. of Komex International Ltd. B. K. Moore, P.Eng. of DPH Engineering Inc. A. P. Agnew, P.Eng. of Cimarron Engineering Ltd. I. G. Jones, P.Geol. of Geo Engineering (M.S.T.) Ltd. D. B. Ramsay, M.N.R.M. of Ramsey and Associates Consulting Services Ltd. P. M. Ruby, M.S.W. of P.M. Ruby Consulting Inc. V. T. Hohn of Verve Unlimited (Inc.)
Cimarron Petroleum Ltd. (Cimarron) R. Giammarino, P.Eng.	
Suncor Inc. (Suncor) G. D. Wong, P.Eng.	
Public Advisory Committee (Advisory Group) D. R. Ganzeveld	D. R. Ganzeveld

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
County of Grande Prairie (County) R. Pfau	R. Pfau
Sexsmith Chamber of Commerce (Chamber) B. Thoreson	B. Thoreson
Town of Beaverlodge A. E. Gaudin	A. E. Gaudin
Town of Sexsmith M. Foat	M. Foat
Baron Oilfield Supply B. Smith	B. Smith
Northern Metalic Sales (Alta.) Ltd. H. A. Side	H. A. Side
Peace Tech Services Ltd. A. T. Moug	A. T. Moug
Prairie Truck and Trailer Parts Ltd. E. Tschaja	E. Tschaja
Residents of LaGlace/Sexsmith D. R. Ganzeveld	D. R. Ganzeveld
Rodney D. Elvestad	R. D. Elvestad
Fred Estlin	F. Estlin
Dennis R. Ganzeveld	D. R. Ganzeveld
Donald L. Johnson	D. L. Johnson
Bill Kirkham, Jr.	B. Kirkham, Jr.
Dan Kirkham	D. Kirkham
Mary, Bill, and Kelvin Kirkham M. Kirkham	M. Kirkham
Joan Pol	J. Pol

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Group of Local Residents (the Carter Group) J. D. Carter, Q.C.	E. Borysiuk S. Craipley L. Good-Gerow A. Iwaskow K. McLean F. Slauenwhite
Lesser Slave Lake Indian Regional Council (the Indian Council) K. E. Buss	Chief James G. Badger Elder J. T. Bellarose Elder D. Cardinal Elder V. Chalifoux Elder A. Halcrow Elder J. Testawitch Elder F. Willier H. Giroux L. Willier
Peace County Agricultural Protection Association (the PCAP Association) - Alberta Chapter: H. J. Pirker - B.C. Chapter: S. Hartnell	H. J. Pirker
Lee Morin	L. Morin
Allan H. Johnstone	A. H. Johnstone
Alberta Environmental Protection (AEP) W. A. McDonald	
Energy Resources Conservation Board staff R. D. Heggie W. A. MacDonald, P.Eng. J. L. Spangelo, P.Eng. K. J. Bahadur, P.Eng.	B. Olson

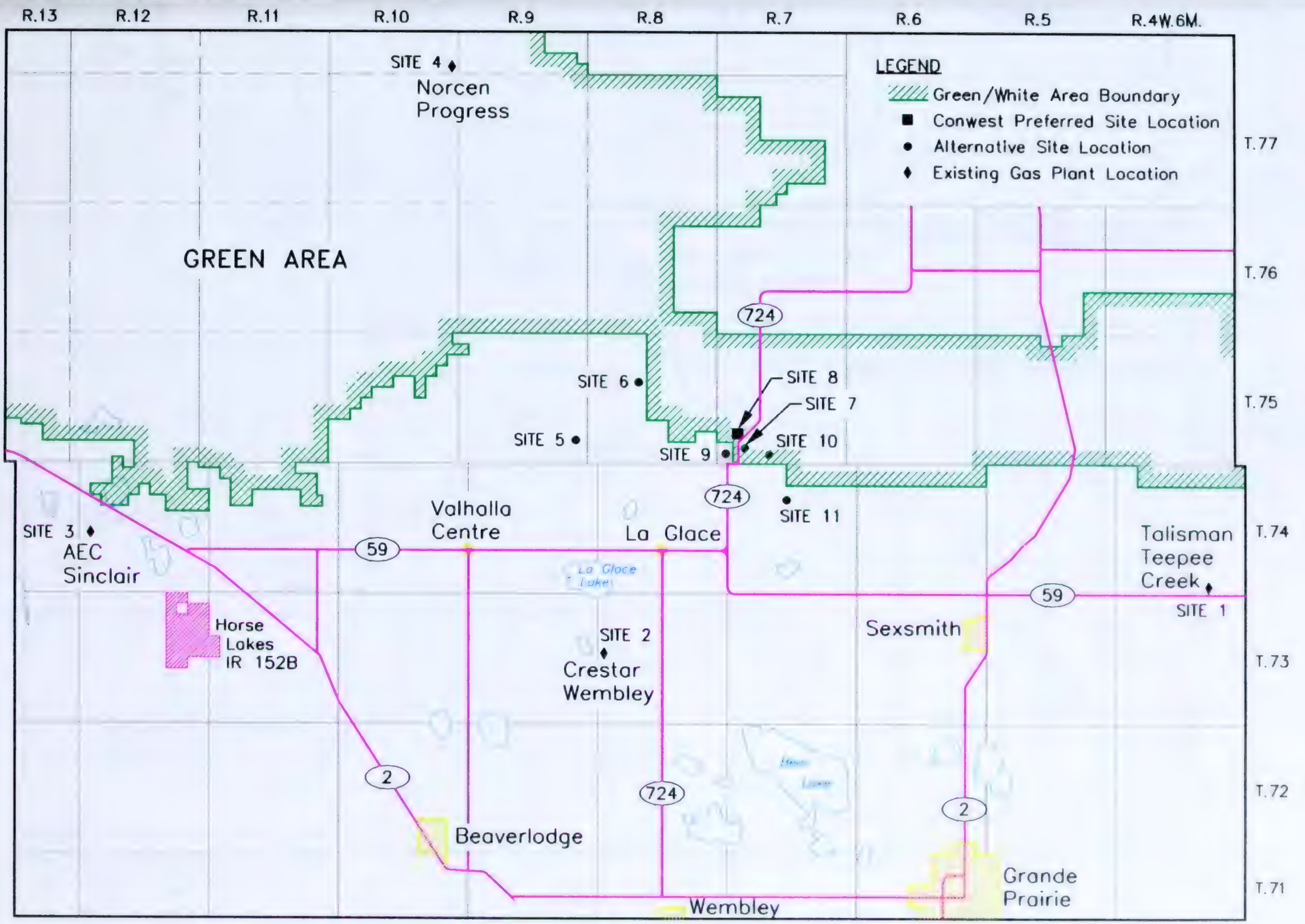


FIGURE 1 Proposed Conwest Gas Development/Area Overview
Applications No. 931148 and 940446 to 940450
Conwest Exploration Company Limited

D 94-6

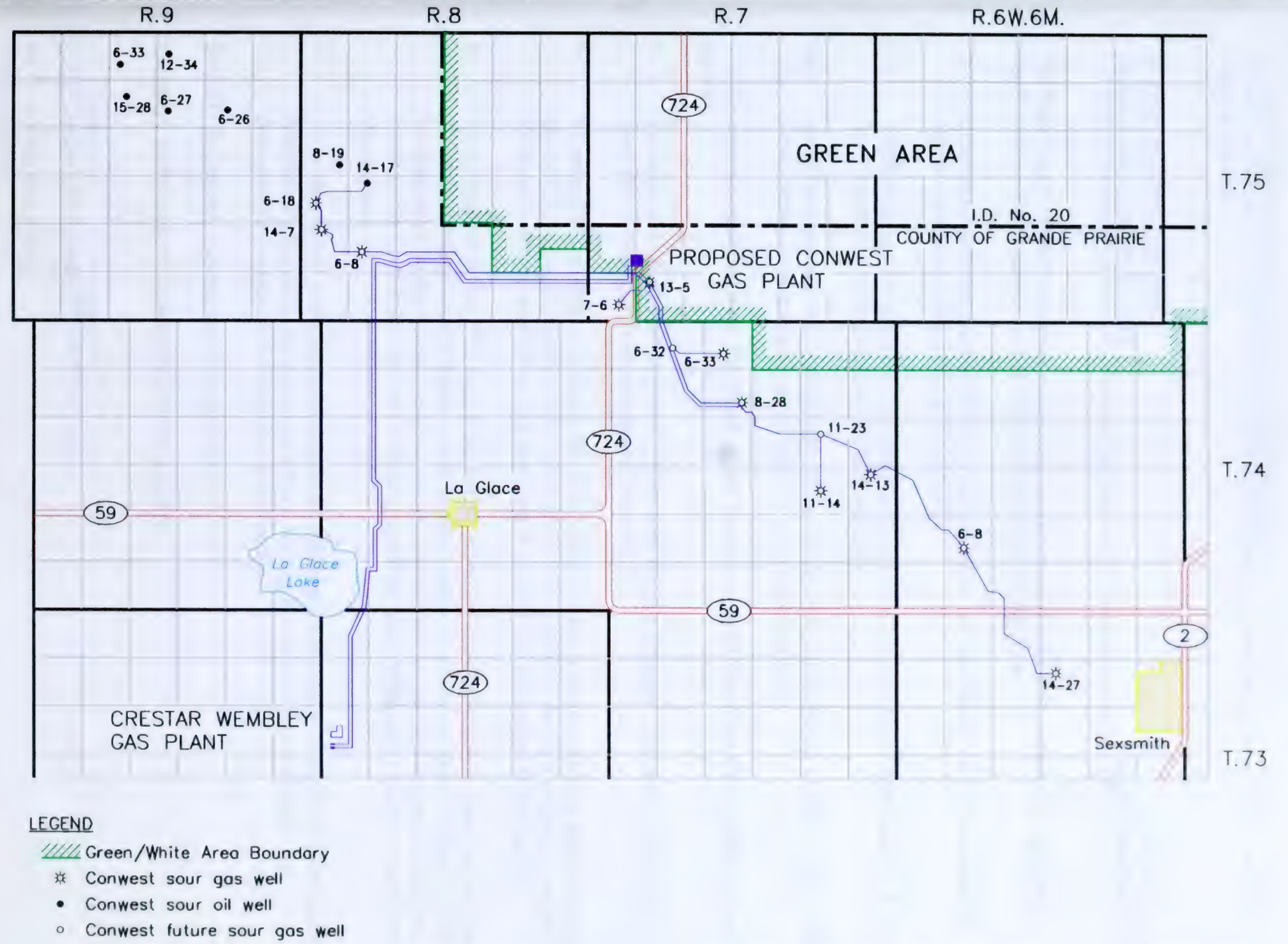


FIGURE 2 Proposed Conwest Gas Development/Routes of Applied-for Pipelines
Applications No. 931148 and 940446 to 940450
Conwest Exploration Company Limited

D 94-6

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BALOIL RESOURCES LTD.
ZAMA LAKE POWER PLANT

Decision D 94-7
Application No. 931409

The Board has reviewed the report of its sitting Members, attached hereto, respecting Application No. 931409 by Baloil Resources Ltd. (Baloil) requesting the ERCB to:

(i) order Alberta Power Limited (APL) to connect with and take electric energy generated by Baloil's proposed power plant at Zama Lake;

(ii) establish terms and conditions for determining the basis for payment of compensation by APL for the electric power that would be generated; and

(iii) adopt the views and recommendations set out in the 1988 ERCB/Public Utilities Board (PUB) Small Power Inquiry Report as the basis for setting compensation.

For the purposes of its decision, the Board adopts the recommendations of the sitting Members and decides:

- To order APL to connect its power system with Baloil's proposed plant and to purchase power from Baloil at a price to be determined by the PUB.

- To amend and condition Approval No. HE 9206 by adding a clause requiring Baloil to satisfy the ERCB, within 12 months of the date that the PUB makes its decision respecting the price for Baloil's energy generation, that financing is in place and the project is proceeding.

- To recommend to the PUB that, when setting prices for Baloil's output, it considers that, prior to new generating capacity being needed in the province, the value of Baloil's output should be comparable to the Alberta marginal energy cost adjusted for savings in transmission line losses to the Zama Lake area and a capacity credit be added when new capacity is needed in the province.

- To recommend to the PUB that it should not consider a levelized price method unless adequate contractual safeguards are in place to ensure that any potential risk to consumers from premature abandonment of the project is acceptable.

DATED at Calgary, Alberta, on 15 August 1994.

ENERGY RESOURCES CONSERVATION BOARD

N. G. Berndtsson, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BALOIL RESOURCES LTD.
ZAMA LAKE POWER PLANT

Examiner Report E 94-4
Application No. 931409

1 APPLICATION AND HEARING

Baloil Resources Ltd. (Baloil) applied to the Energy Resources Conservation Board (ERCB), pursuant to section 17(5) of the Hydro and Electric Energy (HEE) Act, requesting the ERCB to:

(i) order Alberta Power Limited (APL) to connect with and take the electric energy generated by Baloil's proposed power plant at Zama Lake;

(ii) establish terms and conditions for determining the basis for payment of compensation by APL for the electric power that would be generated; and

(iii) adopt the views and recommendations set out in the ERCB/Public Utilities Board (PUB) Small Power (SPP) Inquiry Report as the basis for setting compensation.

Baloil also applied to the PUB, pursuant to section 17(6) of the HEE Act, to:

(i) determine the amount of compensation payable for the electric power that would be generated by its power plant; and

(ii) set the price for that energy at 4.7 cents per kWh.

Baloil further requested that, if the ERCB and/or the PUB find that its request cannot be addressed as set out above, the ERCB and/or the PUB make whatever alternative evaluations and take whatever other actions are necessary to resolve the issues and set a price for electric power to be generated by the Baloil Zama power plant.

The application was considered at a concurrent ERCB/PUB hearing on 8 February 1994, in Calgary, Alberta, with J. P. Prince, Ph.D. and R. G. Evans, P.Eng. sitting for the ERCB and A. C. Barfett and N.J.R. Dunstan sitting for the PUB. Under the Energy Resources Conservation Act, a division of the Board making a decision must have at least three members. Therefore, the two sitting ERCB Members will provide their findings and recommendations to the full Board of the ERCB for a decision. The Board may accept, in full or part, or reject the recommendations. Its decision is provided along with the sitting ERCB Members' report.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Baloil Resources Ltd. (Baloil) A. F. Balasch	A. F. Balasch, P.Eng. J. N. Tanner L. W. Force L. A. Quinn, P.Eng.
Alberta Power Limited (APL) D. Sabey, Q.C.	B. Laing, P.Eng. W. J. Beckett, P.Eng. B. E. Michael, P.Eng. R. Belland
The City of Lethbridge (Lethbridge) P. Smith, Q.C.	
The Town of Fort Macleod (Fort Macleod) Dr. A. C. Jackson	
TransAlta Utilities Corporation (TAU) T. Dalgleish, Q.C.	
Industrial Power Consumers Association of Alberta (IPCAA) D. E. Crowther	
Municipal Intervenors (Municipalities) C. R. McCreary	
City of Calgary (Calgary) R. F. Goss	
Edmonton Power (EP) D. Topping, P.Eng. R. Cowburn	
Alberta Cogenerators Council (Cogen) K. Logan	
Independent Power Producers Society of Alberta (IPPSA) J. D. Keating N. Teekman	

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Resources Conservation Board staff (ERCB staff) C.J.C. Page P. E. Wickel, P.Eng. J. F. Wilson, P.Eng.	
Public Utilities Board staff (PUB staff) A. P. Merani	

2 BACKGROUND

On 24 July 1991, Baloil submitted an application to the ERCB for approval to construct a 2.5-MW power plant in the Zama Lake area and connect it to APL's electric system. The plant would be fueled by flare gas or uneconomic shut-in gas.

At the time of Baloil's application, APL indicated a need to strengthen the reliability of supply in the Rainbow Lake area by either installing additional generating capacity or constructing new transmission facilities. Baloil indicated that APL had expressed an interest in its project.

In November 1991, APL made application to the ERCB for approval to install a 40-MW gas-fired combustion turbine at its Rainbow Lake power plant. The new unit would supplement the supply of power to the area load which was expected to increase significantly. It would also provide reserve capacity and backup in case of outage of the single transmission line that carries power from central Alberta to the Rainbow-Zama area. The application was later withdrawn because of decreased load growth expectations for the north-west area of the province.

Although the area load growth did not warrant installation of a 40-MW unit, the growth was such that the security of supply to the area needed to be strengthened by 1993. After reviewing all available options, APL determined that relocating an existing 20-MW gas-fired turbine from its Simonette generating station to the Rainbow Lake station would be more cost effective than building new transmission facilities and would adequately resolve the concern about the security of supply for the north-west Alberta area for a few years.

In August 1992, the ERCB issued Approval No. HE 9206 to Baloil on the basis that APL indicated it was prepared to connect the plant if a power purchase agreement could be reached, the potential advantage of using flare gas, and the fact that no objections to the project were filed in response to the ERCB Notice for Objection. The ERCB approval was subject to a power purchase agreement being reached between Baloil and APL within 6 months of the date of the approval. The approval also stated that, in the absence of an agreement being reached, Baloil could apply to the ERCB and request a basis for determining the value of the power plant output.

Recognizing the need to strengthen the power supply in the north-west part of the province in 1993, the ERCB also approved relocation of the Simonette unit to the Rainbow Lake power plant. This approval was issued on 5 October 1992.

In the meantime, Baloil and APL continued negotiations toward a power purchase agreement. In early 1993, Baloil advised the ERCB that, although negotiations with APL were still proceeding, they had not resulted in a power purchase agreement. Baloil applied to the ERCB, on 29 January 1993, to extend the period by which a power purchase agreement would be reached between Baloil and APL. The ERCB approved the request and extended the time to 31 December 1993.

Subsequent negotiations between Baloil and APL failed to reach an agreement on the price that APL would pay Baloil for the energy generated at the proposed power plant. Therefore, following the direction provided in Approval No. HE 9206, Baloil filed the subject application with the ERCB and PUB on 30 September 1993.

3 PRELIMINARY MATTERS

3.1 ERCB Jurisdiction and Authority to Prescribe Terms and Conditions

3.1.1 Views of the Applicant

Baloil did not address the issue of ERCB authority and/or jurisdiction. However, in its application, it requested that whichever Board, the ERCB or the PUB, has the authority should establish terms and conditions for determining the basis for payment of compensation. It left it up to the Boards to decide which one had the authority.

3.1.2 Views of the Interveners

APL submitted that the role of the ERCB under section 17(5) of the HEE Act is to determine whether compensation is payable and, if so, by whom. APL also submitted that, in view of the fact that the parties failed to reach agreement, it is the PUB's jurisdiction to determine the amount of compensation. By necessary implication, the PUB, in determining the amount, must determine the methodology or basis for such determination.

IPCAA submitted that the ERCB lacks jurisdiction to issue an order of the nature which Baloil has requested pursuant to section 17(5) of the HEE Act, stating that the determination of the amount of compensation is exclusively the jurisdiction of the PUB. IPCAA also submitted that the ERCB may not dictate terms and conditions unless and until it issues an order requiring such purchase pursuant to section 17(2) of the HEE Act and, furthermore, the PUB may not exercise its jurisdiction until the ERCB issues an order under section 17(2).

The Municipalities concurred with IPCAA that terms and conditions should not be determined until the ERCB has issued an order requiring APL to buy power from Baloil. The Municipalities also submitted that jurisdiction to fix the amount of compensation rests with the PUB. Compensation should be determined if an agreement between the parties has not been reached, but only after the ERCB has granted its order requiring the purchase and has, if it so chooses, set out the terms and conditions of the purchase.

Lethbridge submitted that, while there is no specific order under section 17(2) regarding the connection, it is possible to infer such direction from the terms of Approval No. HE 9206, which would justify consideration of orders under sections 17(5) and 17(6).

TAU submitted that the only matter for the ERCB to decide is whether APL ought to be ordered to purchase power from Baloil. If the ERCB decides such an order is to be made, then the only outstanding matter is the pricing, which is a PUB matter.

Calgary stated that the ERCB has jurisdiction under section 17(5) to establish terms and conditions relating to the connection, such as times, places, amount of energy, etc. However, the ERCB does not have jurisdiction to establish terms and conditions regarding price. Calgary concluded that, if the parties cannot agree on a price, which is the case before the Boards, then the PUB has sole jurisdiction under section 17(6).

EP submitted that it concurs with the positions of APL and Lethbridge that the ERCB has the authority under sections 17(2) and 17(5) of the HEE Act to attach terms and conditions to, and to order the purchase of electrical energy from, Baloil's proposed power plant. The PUB has the authority to determine the price of the electrical energy from the project under section 17(6) of the HEE Act, but only after the ERCB has issued an order under sections 17(2) and 17(5).

Cogen submitted that section 17(5) allows the ERCB to identify those aspects of the proposed project which should be considered as compensable and stated that the PUB should take this into account in arriving at the amount of compensation.

3.1.3 Views of the ERCB Members

The ERCB Members agree with those interveners who contended that, to issue an order under section 17(5) of the HEE Act, setting out terms and conditions for a connection or purchase of power, the ERCB must first issue an order under section 17(2)(b) requiring the connection of the power plant to APL's system and section 17(2)(c) requiring APL to buy output from the plant. Accordingly, the ERCB Members will review the potential merits of this project and, if they find them to be significant enough and in the public interest, recommend that the ERCB issue an order requiring the connection of the plant to APL's electric system and also requiring APL to buy the energy generated.

The ERCB Members believe that section 17(5) of the HEE Act allows the ERCB to at least recommend to the PUB that it take into account factors that are relevant to the public interest, such as operational benefits, environmental benefits, resource conservation benefits, benefits of technological innovation, etc. This makes the findings of the ERCB available to the PUB to use in determining a pricing mechanism that would reflect not only direct cost versus revenue, but also those other factors that are considered relevant to the public interest under the HEE Act. The PUB derives its jurisdiction on this issue from section 17(6) of the HEE Act and, therefore, must look to the purposes of the HEE Act and evaluate, in the broader public interest, whether, and to what degree, costs associated with such other factors should be passed on to Alberta electric consumers, or whether some other method of cost recovery would be appropriate.

3.2 Status of Approval No. HE 9206

3.2.1 Views of the Applicant

Responding to questions by APL, Baloil testified that it considers its approval to be valid until the issue of compensation for its power plant output is decided by the ERCB and the PUB.

Baloil stated that it had complied with the conditions of the approval. It explained that the approval contained clauses giving Baloil until 31 December 1993 to reach agreement with APL and, if no agreement could be reached, Baloil could apply to the ERCB for a determination of the method of compensation.

3.2.2 Views of the Interveners

During cross-examination, APL questioned the status of Approval No. HE 9206, indicating that a condition of the approval stated that Baloil had to satisfy the ERCB by 31 December 1993 that a power purchase agreement had been reached, a condition that Baloil had not met. In its final argument, APL stated that the approval for this project had lapsed.

3.2.3 Views of the ERCB Members

The ERCB Members believe that Approval No. HE 9206 is still valid because Baloil met the conditions in the original approval by requesting the current proceedings. By having a price set by the regulators, Baloil would be able to bring to a conclusion its price negotiation with APL.

4 DEFINITION OF THE ISSUES

The ERCB Members have considered the application, submissions, and testimony provided at the hearing and consider the relevant issues to be:

- the status of the Small Power Inquiry, and
- whether or not APL should be required to connect to and buy power from Baloil based on consideration of the following factors:
    - need
    - operating benefits
    - resource conservation
    - environmental benefits
    - cost to consumers
    - risk

5 STATUS OF SMALL POWER INQUIRY

5.1 Views of the Applicant

Baloil submitted that, as a result of the SPP Inquiry, there is an SPP policy for non-utility developers of projects with capacities up to 2.5 MW, that are outside of the Small Power Research and Development Program (the SPRD Program). It stated that the findings and recommendations contained in the SPP Inquiry Report were endorsed by the Premier of Alberta and the Minister of Transportation and Utilities, and the report is currently referred to as the "other small power policy" by the Department of Energy. Furthermore, Baloil submitted, it had confirmed with ERCB staff that there were two categories of SPPs, those using renewable energy sources and subject to the SPRD Act and those that were covered under the more general SPP policy as set out in the SPP Inquiry Report. Also, Baloil stated that it had confirmed with the Department of Energy that, after endorsing the findings and recommendations set out in the SPP Inquiry Report, the government gave favourable treatment to a subset of small power producers in the SPRD Act and that the general SPP policy, as set out in the SPP Inquiry Report, would apply to other small power producers.

Baloil submitted that the SPP policy was founded on principles that are still valid. These include encouragement of larger numbers of small electric sources, reduction of the monopoly in the electric generation industry, streamlining the regulatory process, and encouragement of innovation in the power supply sector. Baloil believes its project would contribute to all these principles.

Baloil submitted that the SPP Inquiry had determined that it is in the public interest to require utilities to buy energy generated by SPPs at prices set out in the SPP Inquiry Report. Furthermore, there has not been a change in policy to detract from the findings and conclusions of the SPP Inquiry.

5.2 Views of the Interveners

APL submitted that, as a result of the recommendations contained in the SPP Inquiry Report, the government enacted the SPRD Act and implemented the SPRD Program. Therefore, the SPP Inquiry has no legal status and should not be used to establish a pricing method or to set prices. APL submitted that assumptions made during the SPP Inquiry are no longer valid today. APL stated that it does not disagree with the methodology the Boards recommended as a result of the SPP Inquiry because it seemed appropriate at the time. However, with lower than expected load growth and increased interest in competitive electric generation, the findings of the SPP Inquiry are not in the best interest of Alberta at this time.

APL also submitted that one of the recommendations resulting from the SPP Inquiry was to use a pricing method based on long-term avoided costs for the first 100 MW of SPP capacity and stated that, through the SPRD Program, this amount has already been allocated.

IPCAA submitted that the SPP Inquiry Report does not provide an appropriate basis for determining price at this time. It stated that the PUB has already ruled that the SPP Inquiry is not applicable to purchases from independent producers. Moreover, assumptions used in the SPP Inquiry are no longer valid.

Lethbridge submitted that the recommendations of the SPP Inquiry should not form the basis of determination for compensation. Moreover, the recommendations contained in the SPP Inquiry Report have been dealt with through the SPRD Act, which will continue to impose significant financial burden on consumers.

TAU submitted that, in a recent decision, the PUB had already determined that the recommendations set out in the SPP Inquiry Report cannot be used to provide a subsidized independent power producers program outside the SPRD Act. Furthermore, assumptions behind the proxy unit method set out in the SPP Inquiry Report are now significantly out of date and are inappropriate to apply to today's situation.

The Municipalities submitted that the SPP Inquiry Report has no legal standing and should not be used as a basis for determining a purchase price for electric energy from the proposed Zama Lake power plant. The Municipalities further submitted that, although the government stated that it generally endorsed the recommendations of the SPP Inquiry, it nonetheless modified those recommendations and enacted the SPRD Act which is limited to projects using wind, water, and biomass and excludes natural gas (and flare gas) projects. The Municipalities also submitted that much of the information used in the methodology of the SPP Inquiry Report has become outdated.

Fort Macleod submitted that the method outlined in the SPP Inquiry Report for determining avoided cost is an acceptable method.

5.3 Views of the ERCB Members

The SPP Inquiry was initiated after the Lieutenant Governor in Council issued Order in Council 211/87 requesting the ERCB and the PUB to inquire into small power generation in Alberta.

The SPP Inquiry Report contains the findings and recommendations made to the Lieutenant Governor in Council on specific matters outlined in the Order in Council. The Boards recommended that power plants of capacities of 2.5 MW or less be classed as Small Power Generators regardless of the type of energy source, that the price paid for small power generation be based on long-term utility avoided costs, that levelized prices be used, that SPPs should be exempted from certain provisions of the PUB Act and HEE Act, and that these recommendations should be reviewed after 1994 or when 100 MW of SPP capacity is connected, whichever occurs first.

As a result of these recommendations, as well as its own studies, the government enacted the SPRD Act allowing non-utility generators, using renewable fuels, to connect to a public utility and sell their generation at a legislated price, provided they have allocation under the SPRD Program. The HEE Act was also amended to expedite the approval process for projects qualified under the SPRD Program.

The government neither enacted legislation nor amended the HEE Act to give non-utility generators, using non-renewable fossil fuels, treatment similar to those that qualify under the SPRD Act. However, in its press release accompanying the SPRD Act, the government did imply that such projects might be considered for treatment under another "program".

The fact that the government enacted some of the recommendations of the SPP Inquiry in legislation but did not deal legislatively with other aspects of those recommendations, which might be relevant to the project before the Boards, implies that the government of the day ranked certain projects, as defined by the SPRD Act, higher than others. The ERCB interprets that as meaning that this project does not necessarily qualify for special consideration just because it is a power project of relatively small size. However, the government's general acceptance of the SPP Inquiry recommendations also suggests that the project might qualify for special consideration, if there are reasons sufficient to justify that conclusion. The ERCB Members believe that the ERCB has the jurisdiction and responsibility to determine whether special consideration of the project at hand would be in the public interest and, as noted in the previous section, they intend to examine the potential public interest benefits of this project.

The ERCB Members believe that the nature and extent of any special consideration of this project should be determined on the basis of the circumstances under which the project would be operated today, because circumstances have changed substantially since the 1987 SPP Inquiry recommendations were made. Some of the factors that have changed since 1987 include:

- actual and forecast load growth are substantially lower than those assumed at the time of the SPP Inquiry, with the resulting movement of the year in which new capacity may be required by the AIS to possibly the year 2000 or beyond,
- gas prices, inflation rates, discount rates, and the state of the economy in general, are different than assumed in 1987, and projections of all these factors would be different,
- there is an emerging interest, in both government and industry, to find a workable competitive market approach to select new generating capacity,
- initiatives have been suggested to change the operational characteristics of the electric industry through such things as the unbundling of electric service and rates. Such changes may allow private generating companies to have access to utilities' transmission lines,
- there is an increasing amount of work by the utilities and others to develop alternative ways of satisfying electric energy needs, such as Demand Side Management.

In summary, the ERCB Members believe that approval of a project such as that proposed by Baloil cannot rely solely on the recommendations contained in the report resulting from the 1987 SPP Inquiry. It has to be justified on its own merits. An evaluation of the merits of the proposed project follows.

6 NEED

6.1 Views of the Applicant

Baloil submitted that APL had repeatedly informed it during the 1990 to 1992 time period that north-west Alberta was short of generating capacity and that APL welcomed the additional capacity of the Baloil proposal. Furthermore, Baloil submitted that APL, in its application for the Arkenciel power plant (to be located near the existing Rainbow plant), had identified a need for generating capacity in the order of 40 MW and that the 2.5 MW proposed by Baloil would be included in APL's planned additions.

Baloil submitted that APL's current position respecting need for capacity is based on the 1992 Electric Utility Planning Council (EUPC) forecast and that some of the assumptions made by the EUPC back in 1992 were proven pessimistic when compared to actuals for 1992 and 1993. For example, Baloil indicated that the actual inflation rate, Canadian prime rates, and exchange rates for 1992 and 1993 were lower than those assumed by the EUPC forecast. Therefore, it expected that, if these updated rates were used today, the resulting forecast would show higher load growths. Similarly, Alberta's actual real gross domestic product has been following the high bound of the 1992 EUPC forecast, which is another indication that the load may grow at higher-than forecasted rates. Furthermore, Baloil stated, it expects increased oil and gas activity in the north-west portion of Alberta. All these factors suggest that future electric energy requirements should follow the high bound of the EUPC forecast. Therefore, need for new capacity may occur sooner than suggested by APL.

In response to the issue raised by several interveners about competitive bidding as a means of selecting future generating capacity, Baloil indicated that it agreed in principle with the concept of a competitive marketplace in the electrical energy industry. Nevertheless, it believed that its project should be given a place in a queue to build the next increment of generating capacity for the AIS.

6.2 Views of the Interveners

APL submitted that the 1992 EUPC forecast is the most current forecast of electric energy requirements in the province and it is appropriate for 1994. APL stated that it believes that the average load growth scenario, namely the arithmetic mean between the high and the low bounds of the 1992 EUPC forecast, is the most likely to materialize. Based on the average load growth scenario, and the current decommissioning dates of some existing older generating units, need for new generating capacity in Alberta would occur by the year 2000. However, APL expressed the view that extending the life of some older units is a very likely possibility. Therefore, need may not occur before the year 2003.

APL further stated that, back in 1990, there were some very robust load growth forecasts for Alberta, particularly for the north region of the province. However, forecasts have dropped dramatically since then, causing the need for new capacity to move further into the future. APL explained that this was the reason it had withdrawn its application for the Arkenciel power plant and applied instead to relocate the Simonette generating unit to the Rainbow Lake area.

APL also submitted that future generating capacity should be selected on the basis of competition. It expressed the view that establishment of a competitive marketplace for production of electric energy in Alberta is coming. Therefore, approval of the proposed facility now may restrict future competition, resulting in possibly losing a more competitive option that might be available in the future.

Calgary, TAU, and Lethbridge submitted that the ERCB should deny the application because there is no demonstrated need for additional capacity by the AIS and consumers should not be forced to pay for capacity when it is not needed. Furthermore, they were in favour of a competitive market approach for the selection of new generating capacity and indicated that approving Baloil's project now, thereby granting Baloil a place in a queue to build new generating capacity, is not desirable because better options might materialize closer to the year of need.

EP submitted that any proposal by independent producers should pass the same test as utility projects. On this basis, Baloil's project should be deferred until the AIS requires additional capacity.

IPPSA argued that generation from the proposed 2.5-MW power plant would be completely absorbed by local loads. Its addition to the AIS would be unmeasurable as far as forecasting future need and it would not measurably advance or delay the need date for the 400-MW Genesee Unit No. 1.

Fort Macleod submitted that a small increment of 2.5 MW should not be considered in association with the EUPC's projections of future demand because small increments are ideal for inclusion in the overall generation mix and can be introduced into the system in a much quicker and simpler manner than new large thermal plants.

6.3 Views of the ERCB Members

The ERCB Members note that, based on the 1992 EUPC load forecast, need for new generating capacity by the AIS ranges from as early as 1996 to as late as 2003. The earlier date is tied to the high growth scenario of the EUPC forecast. However, actual load growth recorded since 1992 does not support such a high growth scenario.

The ERCB Members believe that, to date, actual load growth and current short- and medium-term economic prospects support APL's position that an average growth scenario is more likely to materialize. Under this scenario, need for new capacity by the AIS is not expected to occur until the year 2000. Therefore, in all likelihood, the proposed project would not have any beneficial effect in the short term because it would neither defer nor replace future AIS generating capacity until the turn of the century.

The ERCB Members acknowledge the views expressed by some interveners regarding competitive bidding and establishment of a queue of approved projects waiting to be built to satisfy a future need. The ERCB Members reiterate the ERCB's position (expressed in ERCB Decision D 93-2) that, although it is prepared to entertain applications for new generating capacity, it does not favour establishment of such a queue. Projects must be justifiable on the basis of need or some other bases that clearly indicate that these projects are in the public interest. Therefore, if the ERCB finds that the plant should be connected and APL directed to take the power, it would consider requiring the applicant to complete the project within a specific period of time. So, even if Baloil's project becomes the first in line it does not retain this position forever. The ERCB Members consider it not unreasonable to require the applicant to satisfy the ERCB that it has obtained financing for this project within one year from the date of any decision of the PUB respecting a price for Baloil's energy generation.

7 OPERATING BENEFITS

7.1 Views of the Applicant

Baloil submitted that its plant would contribute to more reliable electric service in the north-west region of the province and would significantly reduce transmission losses by replacing electric energy that otherwise has to be transmitted from central Alberta. Baloil stated that transmission line losses are in the order of 50 per cent, as cited by APL in its Arkenciel power plant application.

Baloil's project would use natural gas (either flare gas or shut-in gas) in internal combustion engines that would drive induction generators to produce electric energy. Waste heat from engine exhaust and radiators would be used to power a liquids knock-out process. Therefore, there is a small cogeneration aspect to the proposal that makes the efficiency of the entire process greater than 40 per cent.

7.2 Views of the Interveners

APL submitted that there is about 60 MW of load in the region, including load in the Zama Lake area, which is currently served by the Rainbow Lake power plant and from central Alberta via transmission lines. APL also explained that, because the Rainbow power plant is expensive to operate, energy to the area is normally supplied from central Alberta and the Rainbow power plant is kept on standby mode, at minimum output, to ensure reliable service in case of transmission line outages. This situation would not change if the Baloil plant were installed. The Rainbow plant would continue to operate at minimum output. Therefore, Baloil's generation would not displace gas-fired generation at the Rainbow Lake power plant.

APL indicated that transmission line losses to the Zama Lake area are in the order of 50 per cent at peak time. However, on an average annual basis, losses are 38 per cent.

IPPSA submitted that one of the benefits of this project would be a significant reduction in transmission losses.

7.3 Views of the ERCB Members

The ERCB Members note that the way in which APL operates its Rainbow power plant (normally at minimum output) would not be affected by generation from the Baloil plant. Instead, any generation by the Baloil plant would primarily displace energy that the rest of the AIS generates and transmits to the Zama Lake area via power lines originating in the Edmonton area. Therefore, the proposed Baloil power plant, if constructed, would result in reduced AIS transmission line losses to the Zama Lake area, which could be as high as 50 per cent at peak time and 38 per cent on average.

Because the Baloil plant would displace AIS generation, and because (as noted in the previous section) new capacity would not likely be displaced or deferred until the year 2000, the ERCB Members are prepared to recommend to the PUB that the value of the plant output to the year of AIS need should be equal to at least the avoided cost of AIS energy plus any savings in AIS transmission losses. After that credit should also be given for capacity.

8 RESOURCE CONSERVATION

8.1 Views of the Applicant

Baloil submitted that its project would help develop a new way to utilize natural resources which today are uneconomical to produce. It explained that there are two sources of fuel for its project, flare gas and shut-in gas. Flare gas is currently wasted and shut-in gas cannot be economically produced by conventional methods at present-day gas prices or foreseeable prices in the future. However, using them for electric energy generation, which is a more refined product, turns these energy resources into a useful product which is also economic to produce. Baloil stated that, if successful, its idea may turn into a new industry for Alberta with great potential for exports.

With respect to the availability of fuel supply for other projects such as this, Baloil submitted that 91 to 92 per cent of all solution gas in the province is currently recovered by conventional methods. However, the 8 to 9 per cent not recovered, which amounts to approximately 5 million cubic metres (m^3)(175 million cubic feet) of gas per day, is flared. Baloil estimated that, with the method and the technology of its proposed project, 25 to 35 per cent of this amount of gas could be converted to useable energy.

Baloil testified that it had investigated other sites in Alberta where similar projects may be feasible. It indicated that it had identified one or two sites in the Drayton Valley area, three or four near Drumheller, and one or two in other locations in southern Alberta. Baloil also indicated that the capacity of these potential projects could be between 1 and 2.5 MW. However, these sites are owned by others and Baloil is not interested in them.

Baloil stated that the volume of gas dedicated to this particular project, 272 million m^3 (9.6 billion cubic feet)(Bcf), should be sufficient to allow it to operate for more than 20 years. Baloil estimated that only 150 million m^3 (5.3 Bcf) would be used for power generation. Of this, 51 million m^3 (1.8 Bcf) could potentially be flare gas. Baloil explained that initially it intends to use mainly flare gas. As flare gas production is related to oil production and declines over time as oil production declines, it had planned, and had held negotiations with other operators within close proximity to its proposed plant, to gather and collect solution gas to supplement its own production. If and when flare gas becomes unavailable, Baloil would use uneconomic shut-in gas to continue operation of the power plant.

Baloil explained that the 51 million m^3 of solution gas that would be available was calculated by applying a gas-oil ratio in the order of 44.5 to 62 m^3 of gas per m^3 of oil (250 to 350 cubic feet per barrel) to a forecast of oil production. The gas-oil ratio used is an average of that for all wells tied into Baloil's Zama Lake battery.

Baloil submitted that the Zama Lake area has large numbers of wells that produce small amounts of associated gas and many wells have small uneconomical gas reserves in zones uphole from the oil. It stated that it has expertise and experience in completing and operating oil wells in this area. Therefore, its projections of fuel and its ability to provide fuel for the proposed project are reasonable.

8.2 Views of the Interveners

APL submitted that less than one third of the fuel to be used by the proposed project would be from gas that might be flared if the oil wells were to be operated. It pointed out that most of the wells currently are not in operation and very little gas is being flared.

TAU noted that if Baloil's project were totally a flare gas project it might be economic at a much lower price than that suggested by Baloil. To the extent that at least two-thirds of its fuel production is from shut-in conventional gas wells and not flare gas, the project and its economics are similar to a conventional gas-fired generator.

Lethbridge submitted that flare gas constitutes a minimum of only approximately one third of the fuel requirements and that the cogenerating aspect of the proposal is also a very small portion of the total plant output. Lethbridge concluded that the project is essentially a proposal to turn uneconomic gas into uneconomic electricity for Baloil's benefit at a cost to electrical consumers in Alberta and, as such, should not be approved.

EP submitted that the proposal should be considered a gas-fired plant using uneconomic gas because it would utilize only a minor amount of flare gas.

IPPSA submitted that the proposed project would be beneficial because flare gas would be converted into a source of income instead of a waste expense and would create a new source of royalty revenue for the provincial government from flare gas and otherwise uneconomic solution gas.

Cogen submitted that, should the ERCB approve this project, the benefits regarding conservation and prevention of waste of an energy source should be recognized.

8.3 Views of the ERCB Members

The ERCB Members believe that if, through the use of the technology proposed by Baloil, resources which would be lost or wasted could be economically recovered, then that would be a significant benefit to Alberta. To find out if this is the case the ERCB Members reviewed information in the public domain relating to the availability of fuel supply for the proposed project (solution gas and uneconomic shut-in gas) and the potential for similar projects throughout Alberta.

ERCB records show that approximately 1800 million m^3 (63 Bcf) of gas per year, representing 9 per cent of the total solution gas produced in Alberta, is currently being flared. This gas is flared mainly because it may not be economically or technically practical to construct pipelines and gas compression facilities if oil wells are located in remote areas or produce very small volumes of solution gas. Flaring also occurs for well testing and operational reasons such as equipment failures, power outages, pipeline problems, and scheduled maintenance of equipment.

The applicant estimated that, through the use of plants similar to the one it is proposing for the Zama Lake area, 25 to 35 per cent of the flared gas could be recovered. This implies a potential resource gain in the order of 500 million m^3 of gas per year, which may be sufficient to fuel 100 Baloil-type plants. However, the ERCB Members note that this amount of flare gas is spread over more than 4000 wells and batteries, many of them located in remote areas and each flaring small amounts of gas. Therefore, the widely dispersed availability of this gas and the applicant's testimony that it had identified less than ten potential sites where similar projects may be feasible make the ERCB Members believe that the potential recovery of flare gas would be substantially less than what was suggested by Baloil.

In evaluating the "demonstration value" of the project, the ERCB Members must determine its applicability, if successful, elsewhere in Alberta. In this regard, the ERCB Members believe that other projects of this nature may be developed under very different circumstances. For example, they may not be tied to a liquid recovery process, they may generate electric energy for their own use, or they may have intermittent or short-term availability of solution gas, etc. Therefore, the ERCB Members are of the opinion that the demonstration value of Baloil's proposal is less than what was implied by the applicant. Nevertheless, if there is a demonstration value, some portion, if not all of that value, will ultimately flow back to Baloil through the licensing or marketing of any technology it may demonstrate.

With respect to the availability of solution gas to fuel the proposed plant, Baloil estimated that there may be 51 million m^3 (1.8 Bcf) of solution gas that could be produced as a result of oil production at its battery located in Legal Subdivision 9, Section 33, Township 114, Range 6, West of the 6th Meridian. Baloil explained that it had estimated this amount applying a gas to oil ratio of 44.5 to 62 m^3 of gas per m^3 of oil (250 to 350 cubic feet per barrel) to its forecast of oil production from the wells tied to its battery. The ERCB Members accept that solution gas produced by Baloil's oil wells could be turned into useful energy by its proposed power plant. However, they are sceptical of the amount of solution gas claimed by the applicant because it implies an oil production rate of about 75 to 100 m^3 (470 to 630 barrels) per day which the ERCB Members view as very optimistic.

With respect to uneconomic shut-in gas, the ERCB Members accept, based on Baloil's assertions, that there are significant amounts of associated (gas cap) and non-associated gas in the wells which would be sufficient to fuel the power plant for many years. However, the applicant did not present evidence to preclude the possibility that this gas might become economic in the future as gas pipelines and processing facilities develop in that area. This could reduce the size of any benefits attributed to using uneconomic shut-in gas for this project. Also, the ERCB Members view this as a potential risk to the continuing operation of the project. This risk is considered in later sections.

With respect to the recovery of liquids, the ERCB Members recognize that the liquids recovery process of Baloil's proposal has merit with respect to conservation of resources. Furthermore, the fact that the process would utilize waste heat from the power plant, thereby improving the overall efficiency, enhances its merits. While the recovery of liquids represents an improvement in conservation of resources, the ERCB Members note that Baloil intends to market these liquids so they would become a source of revenue to the proponents.

With respect to the applicant's claim that its project would help develop a new way to utilize natural resources which today are uneconomic to produce, the ERCB Members are of the view that the proposal cannot be considered significant from the point of view of the volume of resources that would be conserved. Nor is the project a technological breakthrough, since power generating equipment using solution gas already exists in Alberta without having to sell the electric energy to a utility to make the operation economic.

In summary, the ERCB Members see some merit in this project with respect to liquids recovery, demonstration, utilization of solution gas, and utilization of today's uneconomic shut-in gas. However, these merits are modest, not without risk, and would not support a large premium in the price of power generated by the project. Moreover, to the extent that these aspects of the project are likely to provide direct revenue to the proponents, the ERCB Members would not view them as warranting premiums in the price for the produced electricity.

9 ENVIRONMENTAL BENEFITS

9.1 Views of the Applicant

Baloil submitted that its proposed power plant would be environmentally benign. It estimated that the hydrogen sulphide (H_2S) content in the fuel for the proposed facility would be between 2.5 and 5 per cent. However, it would be removed from the fuel and not released to atmosphere. It explained that the H_2S can be removed by means of an iron sponge process, a Nelson chem-sweet process, or an amine unit. The by-products of the iron sponge and Nelson chem-sweet processes are cartridges which would have to be disposed of in landfill sites. If an amine unit were used, H_2S would be converted to commercial sulphur in the form of a solid. However, the amine unit is much more expensive than the other methods. Baloil submitted that it would use whichever method is the most cost-effective and environmentally acceptable in Alberta.

9.2 Views of the Interveners

APL stated that the project would not be as environmentally benign as claimed by the applicant. It indicated that there may be an environmental benefit only if flare gas were used. However, two thirds of the fuel supply would be from shut-in gas with associated sulphur emissions.

Cogen submitted that, by issuing Approval No. HE 9206 to Baloil, the ERCB determined that the project is in the public interest. What is missing is an indication of the weight to be given to pollution control and environmental conservation benefits. Projects proposing to use waste energy to generate power must be able to sell it to consumers at an appropriate price that recognizes environmental benefits.

EP stated that the production of electricity from gas that would otherwise be flared is an environmental benefit. However, it submitted that Baloil had not given adequate consideration to the capture and disposal of sulphur from the process and that there are minimal, if any, research and development benefits to be gained. EP also submitted that the cost of mitigating environmental emissions created by other industries should be borne by those industries and not by Alberta's electric consumers.

The Municipalities argued that Baloil has not demonstrated that operation of its plant would reduce emissions relative to operation of utility plants.

Fort Macleod recommended that the Board give consideration to the value of the improved environmental technology developed by Baloil.

IPPSA submitted that airborne sulphur emissions and other pollution from flare gas would be reduced. There would also be a reduction in emissions from other electric energy sources whose output would be displaced by the Baloil plant.

9.3 Views of the ERCB Members

The ERCB Members are not convinced that the iron sponge process will effectively remove the H_2S contained in the raw gas. It is public knowledge that this process became common in Alberta 15 years ago. Although it was claimed to remove 10 000 parts per million (1 per cent) of H_2S, experience in Alberta showed that actual quantities of removed were in the order of only 100 parts per million. Furthermore, after some experience was gained with its operation the iron sponge process was abandoned, primarily because it proved to be extremely expensive to operate. Later, increased concern over the environment made disposal of iron sponge refuse more difficult and expensive. Today, there is only one iron sponge process in operation in Alberta and it is used to remove only very small amounts of H_2S. Nevertheless, if the applicant chooses to use the iron sponge process and is successful in removing H_2S from the gas, disposal of iron sponge refuse into landfills would not be environmentally desirable.

Since the ERCB Members are not convinced that the iron sponge process can be used, and since H_2S must be removed from the raw gas before it can be used in the proposed power plant, they believe that Baloil would likely use an amine unit or other more expensive and relatively unproven technology to separate H_2S from the inlet gas stream. The extracted H_2S would have to be either flared to atmosphere or converted into sulphur using a sulphur recovery process. The latter being costly, Baloil may choose to flare the H_2S if allowed to do so. If this were to be the case, an acid flare stack (at some cost) and some extra gas may be required to adequately combust the H_2S and disperse the resulting sulphur dioxide.

The ERCB Members also looked at possible environmental benefits resulting from the plant output displacing generation from other sources. As explained above, the ERCB Members believe that energy generation by Baloil, coming from a sour gas energy source, would have associated sulphurous emissions, particularly if shut-in uneconomic gas is used. Furthermore, the internal combustion process would produce oxides of nitrogen which would have to be emitted to atmosphere. Therefore, if energy from the proposed plant were to displace sweet gas-fired generation, hydroelectric generation, or energy imported through tie-lines, the proposed plant would increase overall acidic emissions in Alberta. If it were to displace only coal-fired generation, the ERCB Members are not convinced that there would be a noticeable decrease in emissions because Alberta coal is known to have very low sulphur content.

In summary, the ERCB Members do not believe this project would have unusual or significant enough environmental benefits to warrant special consideration. The ERCB Members are not prepared to recommend to the PUB that an environmental bonus be added to the value of energy generated by the proposed project.

10 COST TO CONSUMERS

10.1 Views of the Applicant

Baloil submitted that the requested price for the energy generated by its proposed plant would not increase cost to Alberta consumers. It explained that the requested levelized price of 4.7 cents per kWh was set out in the SPP Inquiry Report and was based on long-term avoided cost designed to leave consumers neutral. Because the price would be levelized over the life of the project, consumers would pay a higher than actual price during the first portion of the contract. However, a lower than actual price would be paid during the second portion of the contract that would offset the initial higher price.

In response to arguments that the requested price had been calculated using assumptions that were no longer valid, Baloil presented an example done by APL of avoided cost calculations using the same method as the SPP Inquiry Report but with updated assumptions, in particular the need for new generating capacity commencing in the year 2000 as compared to the year 1995 used at the time of the SPP Inquiry. Baloil stated that results show a 20-year levelized price of 2.98 cents per kWh, assuming only a 3 per cent saving in transmission losses. Baloil estimated that, if a 50 per cent savings in transmission losses were used, then the 20-year levelized price would approach 4.7 cents per kWh. Therefore, it believed 4.7 cents per kWh is still a long-term avoided cost that would leave consumers neutral.

10.2 Views of the Interveners

APL submitted that, until new capacity is needed, electric energy generation by an independent power producer is worth only the incremental cost of energy. In this respect APL submitted year-to-year incremental energy cost calculations that, for example, show figures in the range of 1.7 to 2.2 cents per kWh for 1994, assuming the 1992 EUPC average forecast would materialize. APL explained that the range is because of the uncertainties in the gas price forecast. APL also submitted that it recognizes that the location of the proposed plant is a plus and is willing to increase the Alberta average incremental cost of energy by 38 per cent to account for annual savings in transmission losses to the Zama Lake area. Furthermore, in assessing the value of Baloil's energy generation APL discounted 10 per cent to provide a benefit to consumers. However, it admitted that this figure is arbitrary. As an example, the above marginal energy costs for 1994 increase to the range of 2.15 to 2.68 cents per kWh when 38 per cent is added for savings in transmission losses and 10 per cent is discounted to provide a benefit to consumers.

APL submitted that, if Baloil were to receive 4.7 cents per kWh for its electric energy, consumers would have to pay an extra $400 000 dollars per year. APL explained that this amount was arrived at by taking the difference between Baloil's requested price and what APL believes is the value of energy generation in the Zama Lake area.

TAU described the proposal as a "Technology Marketing Venture" for the test and promotion of technology which may provide the oil industry with a use for flare gas. This may be desirable but the electric consumers of Alberta should not be designated to subsidize it. TAU submitted that, since Baloil and its parent company are seeking to embark on a for-profit venture by means of a test project, they should be prepared to venture the required funding for the test.

Lethbridge stated that the 4.7 cent per kWh levelized payment requested by Baloil assumes a need for new capacity in 1995, an assumption which is no longer valid. Therefore, consumers would be required to pay for capacity not needed, thereby increasing the cost of electricity unnecessarily. Additionally, consumers may be paying increased costs by guaranteeing Baloil a spot in the queue for capacity whereas cheaper alternatives may exist in the future, closer to the time of need. Also, Baloil's project may not be operational at the time in the future when its capacity may be needed.

10.3 Views of the ERCB Members

The ERCB Members accept APL's estimate of AIS marginal energy costs. They also believe that, as mentioned earlier, the value of the energy generated by the Baloil plant to the Alberta consumers should be at least equal to the marginal energy cost plus average (not peak) savings in transmission losses (at least until new capacity is needed by the AIS).

With respect to APL's assertion that a 10 per cent decrease be applied to the marginal energy cost for the benefit of electric consumers the ERCB Members are of the view that this is arbitrary and unwarranted. Electric consumers should be indifferent to any proposal that does not increase their costs. It should not be necessary to provide them with specific price-related benefits. Therefore, the ERCB Members are not prepared to recommend to the PUB that such a 10 per cent reduction be considered.

11 RISK

11.1 Views of the Applicant

In responding to the arguments of interveners, Baloil cited risk issues present in its project and the need to deal with them in order to obtain financing. The first two cited were production levels and costs. The third, and most important to the viability of the project, was the risk of receiving a variable price that would produce revenues less than costs. To finance a project the lender would want to be sure that revenues are secure over the amortization period of the project. Thus, a levelized price is requested in order to allow the non-utility small power project to finance itself. Large power producers do not have to convince their lenders of the financial stability of their projects and, therefore, have no need of a levelized price.

Baloil stated that it recognized that under changing economic conditions and risk the plant may become uneconomic to operate at a levelized price after 10 years or more. Such risk is greater for a 20-year contract than a 10-year contract. Nevertheless, it may be possible to alleviate these concerns by means of a performance bond or an assignment of gas reserves needed to service the project. However, any significant additional up front cash requirement may jeopardize the economic feasibility of the project.

Baloil pointed out that the life of the equipment would be 20 years and it would not be practical to move it to another location before the 20 years expires. Also, cash flow is required from the project for its 20-year life to show a sufficient rate of return. A 20-year sales contract is also necessary to justify the capital expenditure and to ensure the necessary financing. Additionally, although a 20-year sales contract is necessary for the project to proceed, it may be acceptable to set a levelized price for a shorter period subject to a mechanism assuring a 20-year contract period.

It suggested that if the length of contract were to be shortened that it should be at least 10 years and contain enough price security to ensure that adequate debt financing could be secured for the 10-year term. Respecting a performance bond, Baloil suggested that the requirements of such a bond be limited to payments above a reasonable estimate of avoided energy costs, taking into consideration the value of a long-term contract.

11.2 Views of the Interveners

APL stated that, if the proposed project is to be successful from the developers' viewpoint, its development and operation entailed passing on a number of unacceptable risks to electric consumers.

APL cited the economic structure of the proposed project as a weakness that put the consumer at risk over the life of the project, especially in the latter years. With the levelized price requested by Baloil, a significant portion of total capacity payments would be advanced to the front end of the project's life.

Given the cost structure cited, it is possible that Baloil's costs might exceed its revenues in later years and it would no longer be in its economic interest to produce for the full 20 years of the contract. If that were to happen, consumers would never realize the benefit of future capacity they had already paid for and the capacity from Baloil's plant would have to be replaced.

APL also cited the experimental nature of the project and the risk of the plant not being available for normal operation when needed. As well, the possibility of project termination because of excessive operating costs relating to its experimental nature was raised.

TAU observed that Baloil's proposed levelized payment structure would allow the payback of the project's capital costs within 4.5 years. This, along with the prospect of negative cash flows in the latter years because of increasing operating costs, made it unlikely that Baloil would willingly continue to operate the plant for the full lifespan of the project. It concluded that the project, as proposed, put the consumers at risk since they were being asked to subsidize the project in its early years.

Lethbridge submitted that Baloil should not receive any capacity payment on a levelized basis or otherwise. Capacity is neither needed in Alberta nor in north-west Alberta in the foreseeable future. Also, the need for capacity will not occur prior to a substantial portion of the profits being achieved by the applicant. This poses a risk to consumers because the applicant may abandon the project early.

Lethbridge stated that the structure of the transaction afforded a powerful incentive to Baloil to abandon the contract should the costs of continuing to produce power be excessive for the latter portions of the contract, given that the bulk of the return is earned in the first 8 years when none of the capacity of this plant is required by the system. It observed that the applicant did not propose to provide adequate security to protect consumers from this risk.

A further risk it foresaw was the payment of avoided energy costs on a levelized basis. Such payment assumes that the project will deliver energy at all times in a base load mode. Since marginal costs vary by time of day, if the project does not operate during high marginal cost periods, Baloil will be overpaid. It noted that there is no requirement to produce electricity at any particular time in the proposed contract, which creates an economic risk for consumers.

EP submitted that the main issue is risk. Baloil is, in effect, requesting a transfer of risk away from its project and onto Alberta's electric utilities and consumers.

EP argued that the magnitude of the risks associated with the project as proposed were either similar to or less than those that Alberta utilities are exposed to. It suggested that the expected rate of return to Baloil is far in excess of what is reasonable under the circumstances. It cited and reviewed several risks associated with this project. They are:

- Operating Risk – greater in the short term than a utility's but comparable in the long term.
- Fuel Supply Risk – comparable to a utility which invests in long-term fuel supplies and consumes them as required.
- Construction Risk – Baloil's project contains no entirely new technology. Given the rate of change in technology, any generating plant contains some systems which have never been brought together before.
- Financial Risk – meeting this project's debt obligations would be similar to that of a normal business according to Baloil.
- Short-Term Demand Risk – even though there is a surplus on the Alberta system, Baloil is asking that its project proceed and be paid for by Alberta consumers.

- Prudency Risk on Timing – Baloil would be exempt from a prudency review on the timing of its expenditures on the project.
- Long-term Market Risk – the project's profitability is not affected by long-term fluctuations in market demand.
- Regulatory Risk – if the application requesting that APL be required to purchase Baloil's power at a set price is approved, further regulatory review of the contract is unlikely.

The Municipalities supported APL's submission that there is no need for additional generating capacity by the AIS until at least the year 2000. Therefore, if Baloil is granted a levelized price for its energy, AIS customers would be placed at considerable risk because of up-front capacity payments and the possibility of Baloil walking away from the project after it has earned a return on its investments.

The Municipalities submitted that consumers should not be at risk of default by Baloil nor should they be required to prepay capacity payments in advance of need. The Municipalities cited APL's prepayment estimate of $2 million dollars based on excess capacity from 1995 to 2000. If the need for new capacity were extended to 2003 such payments would exceed $3 million dollars. The Municipalities noted that Baloil would recover its initial 2.1 million dollar investment within the first 4.5 years and by 2003 would have recovered an additional 2.8 million dollars.

11.3 Views of the ERCB Members

The ERCB Members see three main areas of project risk which may have an impact on the consumer.

The first area is technological risk. The project is likely to be successful as long as it uses proven technology. If the technology does not work, those results would be evident early in the project life. The project may fail outright or experience increased costs which may cause it to fail early for economic reasons. Either way consumers are not likely to be unduly affected by either additional costs or by paying for electricity not produced. Technological risk is there in the short term, is borne by the proponent and is therefore not a factor for the ERCB Members to consider further.

The second area is financial risk. If the project does not have a sound financial basis it is unlikely to receive financial backing and will not proceed. The financial risk is unlikely to have a direct impact on the consumers as it is borne by lenders and the project proponent. Therefore, the ERCB Members believe it is not a factor for further consideration in the risk analysis process. This financial risk would be reallocated if the PUB were to allow a levelized price. However, this is a matter that would be addressed subsequently by the PUB.

Economic risk is the third and major factor in the ERCB Members' consideration of this project. If the project is approved and proceeds, the level of economic risk presented to the consumer varies depending upon the pricing structure.

Where an unlevelized avoided cost price structure is obtained by the proponent, the consumer assumes no long-term risk and virtually no short-term risk. As energy is produced it is paid for at the current value with no additional payment for the future value of the project.

If a levelized price structure is obtained and is sufficient to finance the project over at least the first half of the 20-year contractual life, as well as earn an adequate return for the owners during that period, the project is likely to proceed. This is despite any remaining economic risks as discussed below. The question that then remains is who will bear the bulk of those remaining risks during the contract period.

Respecting economic risk, there is a risk that costs for fuel, labour, etc. will rise over time and significantly reduce the applicant's net cash flow to the point where operations might cease prematurely. This risk is especially dominant in the latter part of the proposed contract life.

In the short term the gas reserves appear to be uneconomic. However, this situation could change as more reserves are found and as pipeline and processing infrastructure continue to develop in the area. The owners of the fuel reserves may find a more profitable sales opportunity. Fuel supply may become more expensive, less reliable, or unavailable and thus threaten the viability of the project. Assignment of the gas reserves to the project does not necessarily remove that risk. The posting of a performance bond might reduce, but not necessarily eliminate, this risk.

Under the above circumstances, the benefits of a levelized pricing structure flow initially to the project's operator and financial backers throughout the first half of the contract life. Consumers assume the majority of the economic risk with no payback of benefits until the latter half of the contract. Should the project cease operations before the end of its contractual life consumers would suffer a loss.

The ERCB Members note a number of means were suggested that could balance such a situation. They included a performance bond or some other suitable form of financial protection that would be in force during the life of the contract. Other means might include a shorter contract period. The ERCB Members do not propose to dwell on the means that might be used to obtain adequate safeguards. That matter can be more adequately determined if and when the PUB sets a pricing structure. If a levelized price structure is adopted, the ERCB Members believe it should include adequate arrangements for consumers to be safeguarded from undue economic risks.

12 FINDINGS AND CONCLUSIONS

The ERCB Members are not convinced that the connection of Baloil's proposed plant with APL's electric system should be subject to the same terms and conditions prescribed by the SPP Inquiry. Although the concept of using avoided costs that leave consumers "revenue neutral" may still be applicable in this case, the assumptions and methods used to arrive at the avoided cost in 1987 are clearly out of date. Moreover, these were never formalized by government in the form of policy and law. The government did enact legislation and implemented the SPP Program but this was targeted to projects using renewable resources. Baloil's project does not qualify under the program.

Instead, the ERCB Members believe that an order to connect should be based on finding sufficient merits of this project to justify ordering APL to buy electric energy from Baloil, thereby passing the cost of purchase to the electric consumers of Alberta.

Furthermore, if sufficient merits are found, the ERCB may issue a connection order under sections 17(2)(b) and 17(2)(c) requiring APL to buy electric energy from Baloil and, in accordance with section 17(5), attach some terms and conditions. When the PUB considers the application under section 17(6) of the HEE Act it may address matters of broad public interest, such as environmental impact, resource conservation, technological innovation, etc. The ERCB makes its expertise available to the PUB through recommendations and provides the PUB with a broader background on which it can base a pricing mechanism that would take into account the above-mentioned factors.

With respect to the other merits of the project, the ERCB Members have provided a qualitative depiction of these merits in the chart at the end of this section of the report.

The ERCB Members find that, based on the 1992 EUPC load forecast, actual load growth recorded in 1993, and current economic outlook for the province, new generating capacity is not likely to be needed by the AIS until the year 2000. They also find that, before new capacity would be needed in the province, any electric energy generated by Baloil's plant would only replace generation by other sources. However, the replaced energy generation is currently produced in the Edmonton area and is sent to the Zama Lake area via transmission lines, with considerable transmission loss. They conclude that any energy generated by Baloil's plant, which would be located in the Zama Lake area, should be worth at least the incremental cost of energy plus savings in transmission losses. Such losses are in the order of 38 per cent.

The ERCB Members find some marginal merits with respect to liquids recovery and with respect to the utilization of waste heat from the power plant to accomplish that purpose. However, they note that the recovered liquids would be marketed by Baloil to enhance the profitability of its project. Similarly, if the project has a technology-demonstration value, it will ultimately flow back to Baloil through licensing and/or marketing of the technology. Therefore, they conclude that this does not justify a premium in price for the electric energy produced.

The ERCB Members find that utilization of solution gas that is normally flared is a positive step toward resource conservation. However, they note that gas conservation in Alberta is already very high. Therefore, they conclude that the applicability of similar projects throughout Alberta is limited. The ERCB Members also have doubts about the amount of solution gas that Baloil estimates is available for this particular project.

The ERCB Members agree that utilization of uneconomic shut-in gas would be a significant benefit if this gas would otherwise be a lost resource. However, this gas may become economic in the future as gas pipelines and processing facilities develop in the Zama Lake area.

The ERCB Members find that Baloil's project would have higher emissions of sulphur dioxide than a conventional sweet gas-fired plant. This is because of the high sulphur content in Baloil's raw gas (2.5 to 5 per cent) and the ERCB Members' belief that, for technical and economic reasons, Baloil would use an amine unit to separate the H_2S from the gas. Thus, Baloil would most likely flare the H_2S to atmosphere and fuel the power plant with cleaned gas, a process which also involves some emissions of nitrogen oxides. However, even if Baloil chooses to use the iron sponge process and successfully clean the sour gas, disposal of iron sponge refuse into landfills would not be environmentally desirable, and the only alternative, namely disposal at Swan Hills, would be much more expensive.

The ERCB Members also find that electric energy generation by Baloil would increase total emissions in Alberta if it were to displace electric generation by sweet gas-fired plants, hydroelectric plants, or energy imported from neighbouring provinces. If it were to displace coal-fired generation, the ERCB Members are not convinced it would significantly decrease total acidic emissions because Alberta coal is known to have very low sulphur content. Therefore, the ERCB Members conclude that the project would not have unusual or significant enough environmental benefits to warrant special considerations and they are not prepared to recommend to the PUB that an environmental bonus should be added to the value of Baloil's generation.

The ERCB Members find that the most significant obstacle to the project's proceeding is the financial risk which is best handled by a levelized pricing arrangement. However, if Baloil receives a levelized price for its energy generation, there would be a significant economic risk to Alberta consumers. This is because a levelized price would be higher than the actual value of Baloil's output during the first years of the project when the AIS does not need generating capacity. However, in later years, the opposite occurs. Baloil's output would be worth more than the levelized price. Thus, as operating costs increase with time, thereby reducing the operator's net cash flow because revenues are level, there is an incentive to discontinue the project. The proponent may operate the project only during the first years until a sufficient return on investment has been earned, then abandon the project later when it becomes less profitable. Moreover, the risk increases further if the main source of fuel for the project, which is uneconomic shut-in gas, becomes economic in the future as pipeline and processing infrastructure continues to develop in the Zama Lake area. The ERCB Members conclude that, without adequate safeguards for consumers, a levelized price would be unduly risky and not in the public interest.

In summary, the ERCB Members have assessed a number of potential benefits, as shown in the chart, and recognize that there are a certain amount of benefits which are in the public interest. Therefore, they are prepared to recommend that the plant be connected to the AIS and that APL be required to take the output at a price to be determined by the PUB. However, as discussed in this report, the ERCB Members believe that the relatively small benefits to the broad public interest attributable to the resource conservation and demonstration aspects of the project do not justify a subsidy in any form. Therefore, setting a price which recovers more than the AIS short-term avoided cost, adjusted for transmission losses, would not be in the public interest.

The ERCB Members also reiterate their position that the ERCB does not favour establishment of a queue of projects waiting to be constructed to satisfy a future need for generating capacity. However, since they are prepared to recommend ordering APL to take the output of Baloil's proposed power plant, they would consider requiring the applicant to complete the project within a specific period of time so, even if Baloil's project becomes the first in line, it does not retain this position forever.

ASSESSMENT OF POTENTIAL PUBLIC INTEREST BENEFITS OF BALOIL'S PROJECT

	Negative	Marginally Negative	Zero	Marginally Positive	Positive
Need			✓		
Demonstration Project				✓ (*)	
Resource Conservation					
– solution gas				✓	
– uneconomic gas				✓	
– liquids recovery				✓(*)	
Operating Benefits					
– transmission losses					✓
Environmental Benefits					
– H_2S flaring			✓		
– NO_x emissions			✓		
Economic Risk					
– Non-levelized price			✓		
– Levelized price with contractual safeguards		✓			
– Levelized price	✓				

(*) **Indicates there is a benefit but does not require special price considerations because adequate compensation is obtained by the project.**

13 RECOMMENDATIONS

In order to bring the APL/Baloil price negotiation discussions to a conclusion, the ERCB Members are prepared to recommend that the ERCB direct APL to connect its power system with Baloil's proposed plant and to purchase power from Baloil when and if the energy is available. This will allow the PUB to set a pricing mechanism for the purchase of the energy generated by Baloil's plant.

The ERCB Members also recommend that Approval No. HE 9206 be amended with the addition of a clause stating that Baloil has to satisfy the ERCB, within 12 months of the date the PUB makes its decision respecting the price for Baloil's energy generation, that financing is in place and development of the project is proceeding.

Although the ERCB Members cannot find a substantial public benefit, they see a marginal benefit in providing generation using solution gas and uneconomic shut-in gas. They also see marginal liquids recovery and technology-demonstration benefits but believe the proponent would obtain adequate compensation through the sale of liquids and the licensing of technology. Therefore, they do not recommend to the PUB any special consideration for resource conservation and technology-demonstration.

The ERCB Members found no environmental benefits that would warrant special consideration and recommend to the PUB that it should not consider an environmental bonus when setting prices for Baloil's energy generation.

The ERCB Members recommend to the PUB that, when setting prices for Baloil's output, it considers that, before capacity is needed by the AIS, the value of Baloil's output should be comparable to the Alberta marginal energy cost. Consideration should be given to the substantial savings in transmission line losses. The ERCB Members also recommend to the PUB that it should consider adding a capacity credit when new capacity is needed by the AIS. However, because of the potential risk to consumers, the ERCB Members do not recommend a levelized price method unless adequate contractual safeguards are in place to ensure that any potential risk to consumers from premature abandonment of the project is acceptable.

DATED at Calgary, Alberta, on 15 August 1994.

J P Prince

J. P. Prince, Ph.D.
Vice Chairman

R G Evans

R. G. Evans, P.Eng.
Board Member

Decision D 94-8

ERCB

Application for an Exploratory Well Amoco Canada Petroleum Company Limited Whaleback Ridge Area

ERCB

Application for an Exploratory Well Amoco Canada Petroleum Company Limited Whaleback Ridge Area

September 1994

ENERGY RESOURCES CONSERVATION BOARD
APPLICATION FOR AN EXPLORATORY WELL
AMOCO CANADA PETROLEUM COMPANY LIMITED
WHALEBACK RIDGE AREA

ERCB Decision D 94-8

Published by:

Energy Resources Conservation Board
640 - 5 Avenue SW
Calgary AB T2P 3G4

Telephone: (403) 297-8311

Fax: (403) 297-7040

TABLE OF CONTENTS

Page

1 INTRODUCTION 1

1.1 Application 1
1.2 Interventions 1
1.3 Pre-Hearing Meetings and Hearing Schedules 1
1.4 Hearing 4

2 PRELIMINARY MATTERS 4

2.1 Request to Compel the Attendance of Mr. L. Fitch 4
2.2 Rights of the Peigan Nation 7

3 ISSUES 8

4 INFORMATION REQUIREMENTS 8

4.1 Views of the Applicant 8
4.2 Views of the Interveners 9
4.3 Views of the Board 9

5 NEED FOR THE EXPLORATORY WELL 11

5.1 Views of the Applicant 11
5.2 Views of the Interveners 11
5.3 Views of the Board 12

6 LOCATION OF THE EXPLORATORY WELL 13

6.1 Views of the Applicant 13
6.2 Views of the Interveners 13
6.3 Views of the Board 14

7 POTENTIAL FUTURE DEVELOPMENT 14

7.1 Views of the Applicant 14
7.2 Views of the Interveners 15
7.3 Views of the Board 16

8 PUBLIC HEALTH, SAFETY, AND QUALITY OF LIFE 17

8.1 Views of the Applicant 17

8.1.1 Drilling Activity 17
8.1.2 Blowout Prevention 17
8.1.3 Emergency Response Plan 18
8.1.4 Emissions 18
8.1.5 Contaminants 20

8.2 Views of the Interveners 21

8.2.1 Drilling Activity 21
8.2.2 Blowout Prevention 21
8.2.3 Emergency Response Plan 22
8.2.4 Emissions 22
8.2.5 Contaminants 23

8.3 Views of the Board 23

9 PUBLIC CONSULTATION 25

9.1 Views of the Applicant 25
9.2 Views of the Interveners 26
9.3 Views of the Board 27

10 LAND USE 28

10.1 Views of the Applicant 28
10.2 Views of the Interveners 30
10.3 Views of the Board 32

11 DECISION RESPECTING APPLICATION NO. 931598 34

LIST OF TABLES

1 THOSE WHO APPEARED AT THE HEARING 5

2 GROUND-LEVEL H_2S CONCENTRATIONS (PPM) WITH DISTANCE FROM THE 10-18 WELL DURING AN UNCONTROLLED RELEASE 20

LIST OF FIGURES

1 AMOCO HUNTER CREEK DEVELOPMENT AREA 2

2 HUNTER CREEK AREA TOPOGRAPHY 3

APPENDICES

I PRE-HEARING MEETING MEMORANDUM OF DECISION

II INFORMATIONAL LETTER IL 93-9 OIL AND GAS DEVELOPMENTS EASTERN SLOPES (SOUTHERN PORTION)

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION FOR AN EXPLORATORY WELL
AMOCO CANADA PETROLEUM COMPANY LIMITED
WHALEBACK RIDGE AREA
APPLICATION NO. 931598 Decision D 94-8

---

1 INTRODUCTION

1.1 Application

Amoco Canada Petroleum Company Ltd. (Amoco) has applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, to the Energy Resources Conservation Board (the Board) for a licence for a well proposed at a surface location in Lsd. 9-18-11-2 W5M. The well would be known as AMOCO HUNTER CREEK 10-18-11-2 and would be primarily for the purpose of exploring the production potential from the Mississippian System. The well would be located in an area of southwestern Alberta known as the Whaleback Ridge, and more specifically in the valley of Bob Creek (Figures 1 and 2). The Whaleback Ridge area can roughly be described as the area between the Livingstone Range on the west, Highway 22 on the east, Chimney Rock road/Chaffin Creek on the north, and Highway 517/Oldman River on the south.

1.2 Interventions

Interventions both in favour and opposed to the application were received by the Board from numerous groups and individuals. Interventions opposing the application documented concerns with potential wildlife impacts, appropriate land-use issues, personal, community, and lifestyle impacts, and ecosystem degradation. The safety of the public and Amoco's public consultation program were also significant issues to a number of those who made submissions at the hearing. The general view of those interveners opposing the development was that no energy development should be permitted in the Whaleback Ridge area. Those supporting the application generally cited the economic benefits which might accrue from the exploratory well and subsequent field development should the well be successful in identifying hydrocarbon reserves.

1.3 Pre-Hearing Meetings and Hearing Schedules

A pre-hearing meeting was convened at the offices of the Board in Calgary on 14 December 1993. Its purpose was to receive submissions respecting the scope, venue, and timing of the hearing, as well as requests for advance intervener funding. Following this meeting, the Board issued a Memorandum of Decision (Appendix I) dated 31 December 1993. This decision directed that the hearing of Amoco's application would commence on 25 April 1994 in the Maycroft Community Hall. The Board also stated in this decision that the scope of the hearing would largely focus on the proposed exploratory well and its effects, although some flexibility would be allowed for the interveners to address broader issues. A subsequent request by the Hunter Creek Coalition to delay the start of the hearing by two weeks to allow for adequate preparation of its intervention was granted, and the hearing was scheduled to commence on 16 May 1994.

Requests for advance funding were addressed at a meeting on 27 January 1994.

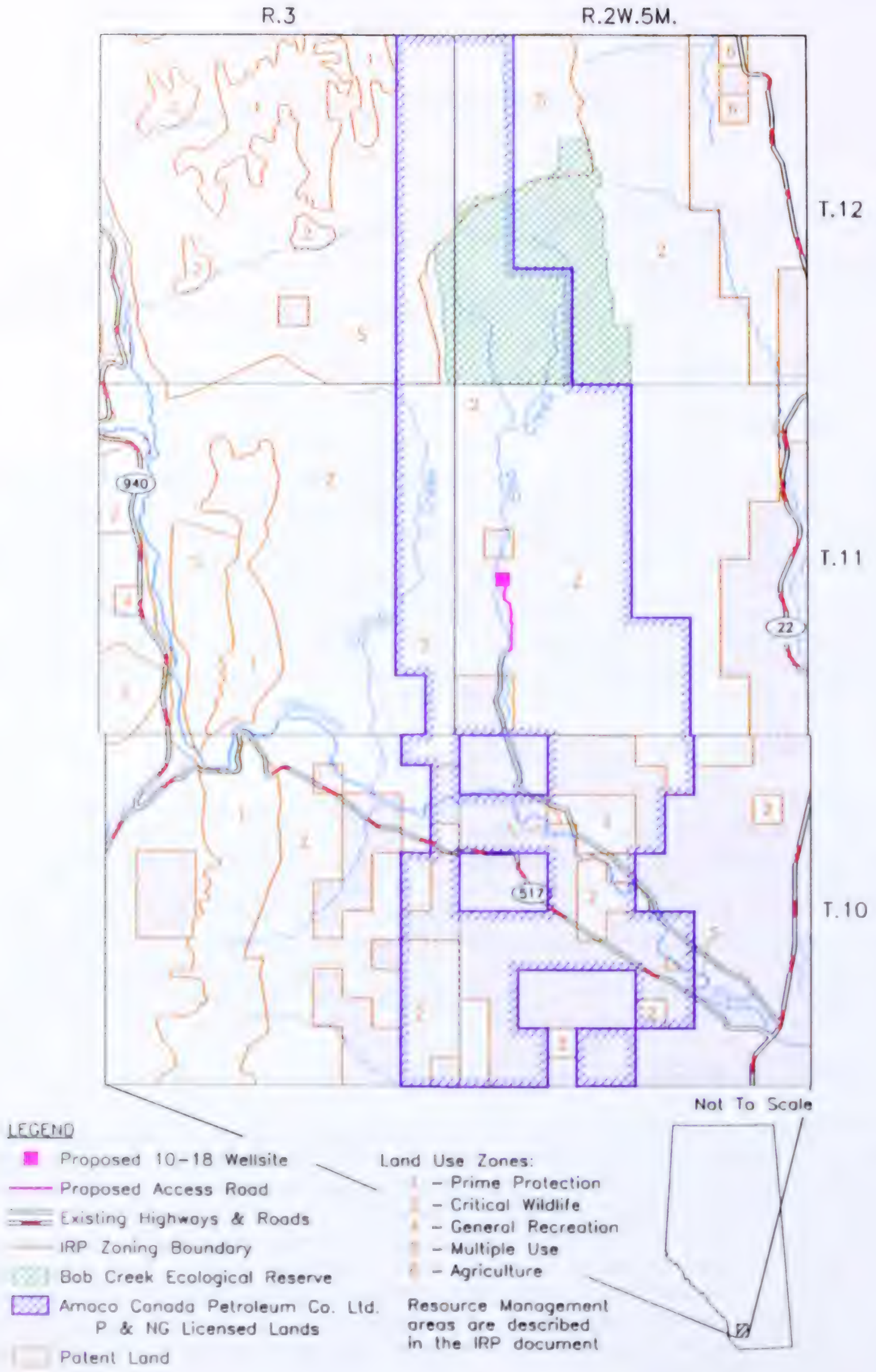


FIGURE 1 AMOCO HUNTER CREEK DEVELOPMENT AREA

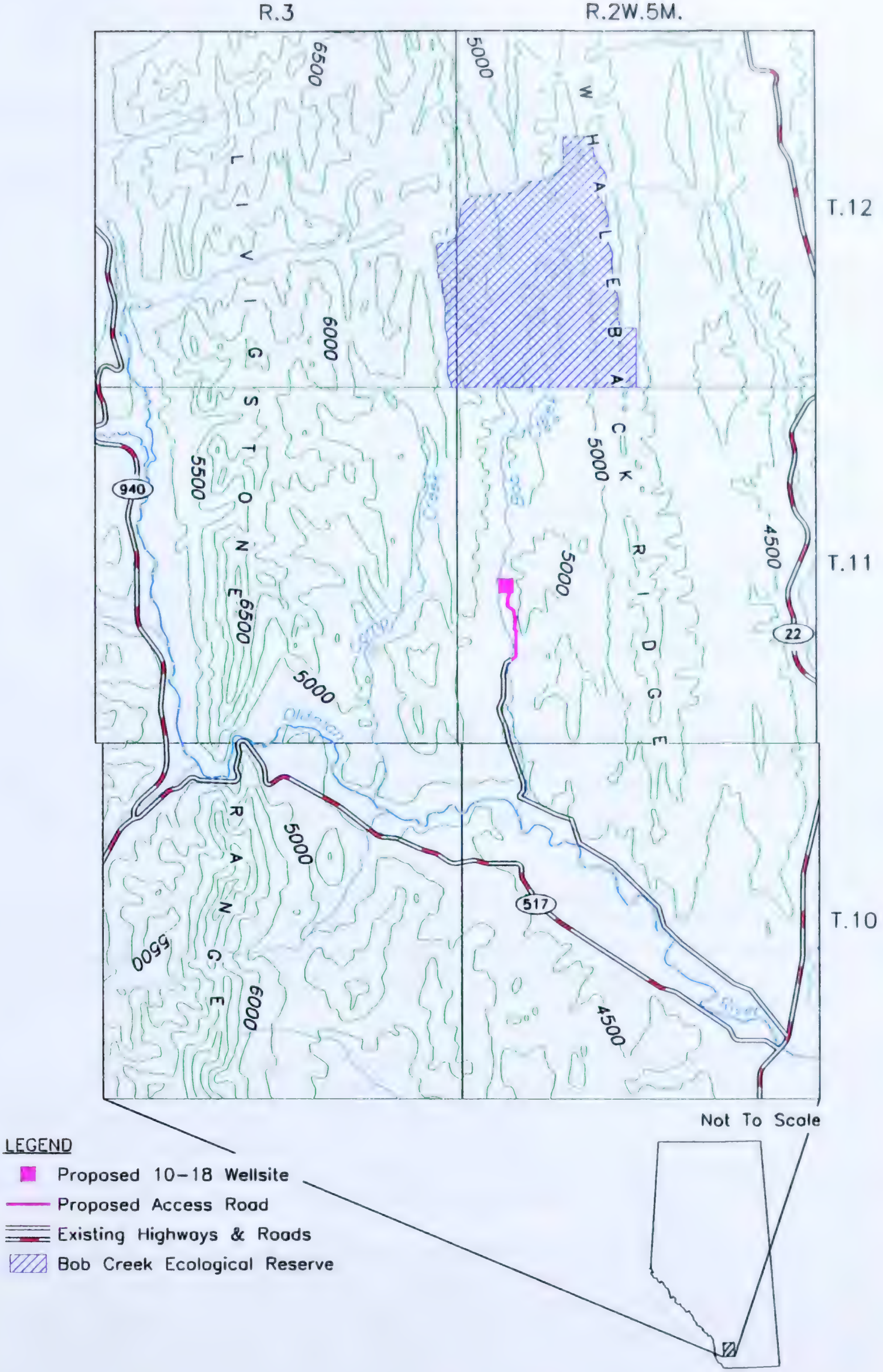


FIGURE 2 HUNTER CREEK AREA TOPOGRAPHY

1.4 Hearing

A public hearing of the application commenced on 16 May 1994 in Maycroft, Alberta, before a division of the Board consisting of F. J. Mink (Chairman), Dr. B. F. Bietz, and R. G. Evans and concluded on 30 May 1994. Those who appeared at the hearing are listed in Table 1.

The following submitted interventions but did not present evidence at the hearing:
Rocky Mountain Ecosystem Coalition, M.D. of Pincher Creek, Village of Cowley, Improvement District of Ranchland No. 6, Castle-Crown Wilderness Coalition, Ida and Verne Dennis, Rick Michalsky, Leo Puerzen, Town of Pincher Creek, Edna and John Drevenak, Val Dennis, Walter Bonertz, James and Veronica Swan, Ron Peters, and Peg Brown.

2 PRELIMINARY MATTERS

2.1 Request to Compel the Attendance of Mr. L. Fitch

At the pre-hearing meeting of 14 December 1993, several interveners advised the Board that they would want staff from Alberta Environmental Protection (AEP) to testify at the hearing. If this participation could not otherwise be arranged, it was asked that the Board request the courts to compel the attendance of AEP personnel at the hearing.

On 29 March 1994, the Hunter Creek Coalition advised the Board that it would be its intention to call Mr. Lorne Fitch, Fisheries Biologist, Southern Alberta Region, Fish and Wildlife Services, AEP, as a witness. The Hunter Creek Coalition then attempted to secure the consent of AEP to have Mr. Fitch appear at the hearing. In a letter dated 14 April 1994, the Hunter Creek Coalition advised the Board that this permission had not been obtained from AEP and thus the Board may be asked to compel Mr. Fitch's attendance at the hearing.

The Board responded to this request in a letter dated 19 April 1994. In its response, the Board denied the request to compel the attendance of Mr. Fitch citing that, although the Board recognized that the environmental impacts of the proposed well were relevant to the hearing, the Board believed that other expert witnesses that would be appearing on behalf of either the interveners or the applicant would be able to deal with those matters.

A written response dated 27 April 1994 from Alberta Justice to the Hunter Creek Coalition summarized AEP's views on the issue. In that letter AEP confirmed that it would not provide Mr. Fitch as a witness at the hearing. It was AEP's opinion that Mr. Fitch had no relevant evidence to give respecting the site-specific details of the application. AEP further felt that there was no compelling reason to believe that the collective expert evidence of the interveners and applicant would be insufficient for the Board to make a decision on the application.

At the hearing the Hunter Creek Coalition again requested the Board compel the attendance of Mr. Fitch as a witness and gave two reasons for its request. The first related to a letter dated 6 January 1994 from Mr. Fitch to the Board. The letter detailed a number of issues related to the wildlife resources in the Whaleback Ridge area and was offered as an approach to reviewing those issues. Board staff distributed a copy of that letter to Amoco as well as to all those who had expressed an interest in the application. The Hunter Creek Coalition said that the only way in which the information in that letter could be adequately examined was to have Mr. Fitch appear as a witness.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco)	R. L. Findlay, P.Biol.
F. R. Foran, Q.C.	J. G. Ward, Ph.D., P.Biol.
J. M. Liteplo	C. H. Dawson, P.Geoph.
D. G. Arnason	D. M. Innes, P.Eng.
	H. J. Vrielink, P.Eng.
	M. J. Miners, P.Eng.
	D. Chalmers
	All of Amoco
	L.E. Morgantini, Ph.D., P.Biol.
	G. Kupfer, Ph.D.
	D. M. Leahey, Ph.D.
	R. E. Dales, M.D.
	J. A. Lore, P.Ag.
	D. E. Reid, P.Biol.
	J. L. Kansas, P.Biol.
Hunter Creek Coalition	
P. E. J. Prentice, Q.C.	T. Smith
G. S. Fitch	H. Smith
	J. Huntley
	M. McCall
	E. Nelson
	J. Nelson
	T. Molson
	R. Nelson
	P. Nelson
	H. W. Thiesson
	W. D. Wishart
	W. A. Ross, Ph.D.
	W. McMillan
	J. R. Eickmeier, P.Eng.
Whaleback Coalition	
G. T. H. Locke	J. A. Tweedie
R. Smith	C. Wallis, P.Biol.
	D. L. Pachal
	K. Van Tighem
	M. Gerrand
	W. Francis
	R. Longair, Ph.D.
Peigan Nation	
C. Figol	B. Pard
	J. C. Elliott, Ph.D.

Antelope Butte Ranch
    H. Lynch-Staunton

D. Sheppard, Ph.D.

S. Marty

K. Jericho

R. Hoff

E. Squair

M. Prusky

Federation of Alberta Naturalists (FAN)
and Alberta Fish and Game Association (AFGA)
    M. Posey
    R. D. MacDonald

W. C. Ranching
    W. Wolbert

Top Hand Industrial Services
    S. Aris

Diamond Hitch Outfitters
    M. Judd

Pincher Creek Chamber of Commerce
    R. Dykin

J. McFarland

Alberta Justice (Representing Alberta Environmental Protection and Agriculture Food and Rural Development)
    R. Bodnarek

Energy Resources Conservation Board staff
    M. J. Bruni
    R. Creasey, P.Biol.
    M. Miller
    P. Oscienny, P.Eng.
    C. Hill

Secondly, the Hunter Creek Coalition believed that Mr. Fitch could best speak to a statement read into the record at the hearing by Alberta Justice on behalf of AEP and Alberta Agriculture, Food and Rural Development. The statement outlined the legislation to which the proposed well was subject, the purpose of the Crown's participation in the hearing and a description of the provincial administrative referral process involved in granting the surface and subsurface dispositions for the proposed well. These included a Mineral Surface Lease (MSL), a Licence of Occupation (LOC) and Petroleum and Natural Gas Rights (mineral lease).

The Whaleback Coalition, the Alberta Fish and Game Association, and the Federation of Alberta Naturalists supported the request made by the Hunter Creek Coalition.

It was the position of the Crown that the Board should deny the Hunter Creek Coalition's request on the basis that it did not provide compelling or substantive reasons as to why the evidence presented by the witness would be critical to the Board's decision or why this information would not be brought out through the interveners' or applicant's expert witnesses.

The Board ruled that it would not compel Mr. Fitch to attend the hearing. The Board stated that there was no new substantive evidence raised since its original decision on 19 April 1994 and it continued to believe that issues raised in Mr. Fitch's letter may be adequately dealt with by experts on both sides of the argument.

2.2 Rights of the Peigan Nation

Although the interests of the Peigan Nation in relation to this single exploratory well licence application have been incorporated with the views of the other interveners on an issue by issue basis, the Board believes it appropriate to separately discuss how the rights and claims of the Peigan Nation would be considered by the Board.

At the hearing, the Peigan Nation noted that it had a number of claims, including ownership of the mineral rights, against the land in question. It argued that a provincial tribunal should not be making decisions which might ultimately interfere with the Peigan Nation's ability to exercise those rights. The Peigan Nation stated that the ERCB does not have jurisdiction, as a branch of the Provincial Government, to abrogate or derogate from the existing aboriginal and treaty rights of the Peigan Nation. The Peigan Nation did not ask the Board to affirm its rights but rather to take the opportunity to understand those rights in the context of the Whaleback exploratory well proposal.

The Peigan Nation also asked the Board to ensure that its rights and interests were taken into account in reaching a decision on the Amoco application. It was noted that any impact the well may have on the Peigan Nation's ability to transmit its culture and identity from one generation to the next would not be in its interest. The Peigan Nation also stated that it had little chance to reap the economic or social benefits which Amoco claimed could accrue to the Province.

The Board recognizes that the Peigan Nation has certain treaty rights which are protected under the Canadian Constitution. Although the Peigan Nation claim that the area of the proposed exploratory well encompasses their traditional rights, this Board is not able to identify to what extent the aforementioned rights apply to this area.

The Board agrees with the Peigan Nation that the issue of what its treaty rights are and where they apply are not matters under the Board's jurisdiction. The Board believes that all interveners participating at the hearing represent interests in the area and it has an obligation to consider and incorporate those interests in deciding the merits in the context of the broad public interest.

3 ISSUES

The Board has reviewed the concerns raised by the hearing participants and believes the significant issues to be considered are:

- information requirements,
- need for the exploratory well,
- location of the exploratory well,
- potential future development,
- public health, safety, and quality of life,
- public consultation, and
- land use.

Each issue is addressed in the following sections.

4 INFORMATION REQUIREMENTS

4.1 Views of the Applicant

Amoco stated that it had gathered and studied a large amount of environmental data and had presented a detailed plan that would allow the drilling of the exploratory well in an environmentally acceptable manner. Amoco stated several times during the hearing that, given typical circumstances for an exploratory well application, the amount of information supplied was extraordinary.

Amoco noted that it had prepared the submission in support of its application to drill the 10-18 well in part in response to a letter of 5 November 1993 from ERCB staff setting out their information requirements. Amoco also referred to Informational Letter IL 93-9 (Appendix II), which sets out the general information expectations of the Board for oil and gas proposals on the southern portion of the Eastern Slopes[1]. Amoco pointed out that this IL had in fact been released six months after the submission of its application and therefore its application had been prepared during a period of changing information requirements. Despite this, Amoco believed that its application also generally met both the spirit and intent of IL 93-9. In particular, Amoco noted that the level of information needed for an initial exploratory well as per IL 93-9 could, in some cases, be less than was required during later proposed development stages. In Amoco's view, this interpretation of IL 93-9 applied to the 10-18 well and was in fact supported by the Board's 31 December 1993 Memorandum of Decision (Appendix I). Amoco pointed to the Board's request in that memorandum that the hearing should focus primarily on the single well described in the application rather than on the full development scenario.

---

[1] Refer to map in Appendix II for description of southern Eastern Slopes boundaries.

At the hearing, Amoco also filed a detailed response to the issues which had been raised by the various interveners. Amoco noted that it did so to help reduce the need to present rebuttal evidence and thus expedite the hearing process.

4.2 Views of the Interveners

The general adequacy of the information provided by Amoco, and whether it had met the more specific information requirements set out by the Board in IL 93-9 and by Board staff in the letter of 5 November 1993, was questioned by the Hunter Creek Coalition, the Whaleback Coalition, and the Peigan Nation. In their view, IL 93-9 in particular set out broad types of information that the Board would need before being able to adequately assess the merits of the application.

Amoco, it was argued, had in fact failed to address a number of issues identified in IL 93-9 as well as some requirements in the letter of 5 November 1993. These included, in particular, the incremental nature and relative significance of the project's impacts. Baseline conditions of particular interest to the Peigan Nation (e.g. the presence of sacred sites, ethnically valuable plants, etc.) were also not considered to have been addressed. It was also argued that Amoco's responses to at least some other issues, such as health impacts, were marginal at best. The interveners believed that, because Amoco had failed to meet the Board's requests for information, the Board had no choice but to deny the application.

The similarity between the wording in IL 93-9 and the Environmental Impact Assessment (EIA) sections of Alberta's Environmental Protection and Enhancement Act (EPEA) was also noted by the interveners. They suggested that IL 93-9 was designed to offer an alternative to the EIA requirements of EPEA since the drilling of oil and gas wells is normally an activity exempt from those requirements. In the interveners' view, this created an additional onus on the applicant to address each of the issues set out in IL 93-9. In their view, IL 93-9 in effect required an EIA and since Amoco had failed to provide such a document, the application must be considered deficient and therefore denied.

The Hunter Creek Coalition also raised concerns with regard to the fairness of Amoco's submission at the outset of the hearing of written responses to issues raised by the various interveners, including the Hunter Creek Coalition. It was argued that, at a minimum, such evidence should be filed in advance of the hearing in order that any cross-examination could be more adequately prepared.

4.3 Views of the Board

When IL 93-9 was developed, it was the intention of the Board that the document would act as a general guide to companies seeking approval to explore for and develop energy resources along the southern part of the Eastern Slopes. Although the oil and gas industry routinely prepares thousands of applications for oil and gas developments throughout Alberta every year, the Board was of the view that this region was sufficiently unique that additional direction to industry was of value. The IL noted the Board's expectation that applicants in this area would place particular emphasis on public consultation and would, to the best of their ability, describe the possible extent of their developments should their initial exploration activities prove to be successful. This latter requirement was set out in order to give both the Board and potentially affected parties a better opportunity to be able to place the proposed development within an overall development context. IL 93-9 also directed that, where feasible, applicants were expected to coordinate their developments with other operators in the region. Finally, applicants were expected to address environmental and social issues in a manner which best reflected the potential sensitivity of the various regions along the Eastern Slopes. The level of assessment would vary as a function of development stage, type, and relative sensitivity of each region.

It is important for all parties to appreciate that IL 93-9 was always intended solely as a guide to the range of information industry should consider in preparing applications within the southern portion of the Eastern Slopes. The guidelines are not intended to be all inclusive of any issues the Board may eventually consider in reaching its final decision. Ultimately, each applicant is responsible for identifying issues and addressing those issues to the degree to which it believes appropriate. The Board is then charged with measuring the application against the broad test of "public interest", including environmental, social, and economic costs and benefits. The failure of any applicant to address one or more of the guidelines set out in IL 93-9 does not automatically mean that the application must also fail, since they should not be viewed as a prescription of the public interest test. Rather, each application will be measured based solely on its overall merits to determine whether granting approval would be in the overall public interest.

A similar test exists in this case with regard to the information request set out in the Board staff letter of 5 November 1993. The staff letter was prepared to assist Amoco in preparing adequate information for the Board to consider the merits of the application. It is site specific, but it encompasses the spirit of IL 93-9 which was being prepared by the Board at that time. Again, the Board expected Amoco to address each question as fully as it believed necessary to convince the Board that its application was in the public interest. Since there were public submissions in this case, the ultimate acceptability of Amoco's application was determined through a public hearing. This report sets out the Board's findings on the various key issues which it has determined are relevant to this particular application.

The Board wishes to emphasize that, with regard to the environmental information required of an applicant, it was never the Board's intention that every application in the southern portion of Alberta's Eastern Slopes would need to address each and every issue set out in IL 93-9. The IL, in fact, clearly states that the level of information appropriate will remain a function of the nature of the proposed development and of the relative environmental sensitivity of the area proposed to be developed. The Board believes that this approach is parallel to that contained in EPEA, which allows discretion to be applied by the Director in establishing the issues which must be addressed in an EIA. The Board believes that a prescriptive, inflexible approach to the provision of environmental information would be neither useful nor appropriate.

It is also important to note that applicants cannot assume, because an issue was not raised by Board staff during their review of an application (e.g. the 5 November 1993 letter), that the issue may not become important, or even pivotal, during the hearing process. Again, the onus remains on the applicant to respond to and/or address all issues which it believes the Board should consider in assessing its proposal, and to do its utmost to discern relevant issues of concern, particularly to residents in the vicinity of the well. The Board also considers the public hearing as a continuum of the information gathering process needed to reach a decision. When a public hearing occurs, the Board accepts that some issues or clarification of information submitted in the application will be developed during the hearing.

The Board considered all the information submitted by Amoco and found that Amoco has generally attempted to meet the intent of IL 93-9. The Board does not accept the intervener position that the application was in some way flawed so badly, due to lack of information, that it should not even be considered. The Board found the information was adequate to proceed to a hearing on the disposition of the application.

5 NEED FOR THE EXPLORATORY WELL

5.1 Views of the Applicant

Amoco indicated that it had obtained the petroleum and natural gas rights from the Province of Alberta to 61 sections in the Whaleback area (Figure 1) and, providing it could demonstrate a commitment to safety and environmental mitigation, that it should be provided a fair opportunity to produce any reserves associated with those mineral rights. Amoco stated that new exploration theories and seismic interpretation techniques, coupled with new seismic data collected in 1992/93, had caused it to believe that a geologic structural anomaly existed in the Whaleback area. The primary prospect was interpreted to be a thrust faulted unit of the Mississippian Turner Valley formation. The validity of the seismic interpretation and the presence of the anomaly could only be confirmed by the drilling of an exploratory well. Amoco further stated that the well would test for the existence of any hydrocarbon-bearing formations present within the structure, delineate the potential size of the structure, assess the possible areal extent of any hydrocarbon accumulations discovered and establish whether these would be capable of economic flow rates.

Under cross-examination, Amoco indicated that the chance of the exploratory well discovering a hydrocarbon-bearing structure in the higher Mississippian system was about 38 per cent and in the deeper Devonian system, much lower, perhaps less than 10 per cent. If the well was successful, Amoco did not consider that it would be commercially productive on its own. The well's primary purpose was to obtain information and it would not be produced in the short term, other than for test purposes.

As one component of the need for the well, Amoco noted that its natural gas production base, as well as that of Alberta, is in decline and that new sources of gas are needed to satisfy growing domestic and export markets. It presented a National Energy Board graph of Canadian Supply/Demand Forecast to support its argument. If the exploratory well was successful, Amoco contended it could ultimately lead to the development of gas reserves of up to 88 700 $10^6 m^3$ (2.5 TCF) with a base case of 42 600 $10^6 m^3$ (1.2 TCF). It submitted that the benefit to the Alberta economy and to government revenues of developing reserves of this size was very significant. This volume could represent an addition of over 2 per cent to the known remaining gas reserves of the province and could provide 2 billion dollars of increased government revenue. Amoco maintained that the exploratory well was therefore in the public interest.

5.2 Views of the Interveners

Those interveners opposed to the drilling of the well argued that, to be considered in the public interest, Amoco must demonstrate that the need for the well outweighed the potential negative social and environmental impacts associated with the well and the access road. They contended Amoco had not provided sufficient technical evidence to support the need for the well. Specifically, they pointed out that Amoco had not filed any geological or geophysical information, such as geological maps or cross-sections, that could be used by the Board to assess the need for the well.

The interveners expressed concern that while the focus of the hearing was primarily on the negative impacts of the proposed single exploratory well, Amoco was presenting the benefits of a successful development scenario. They noted that the only benefits which would be derived from a single exploratory well would be new information and that it was against those benefits that any environmental and social costs should be measured. They also noted that Amoco admitted the odds of a successful discovery and the magnitude of the economic benefits associated with its development were highly speculative. The interveners were not satisfied that the limited benefits and highly speculative nature of the prospect offset the environmental and social costs.

The interveners also disagreed with Amoco's position that the acquisition of a mineral lease should ultimately allow a company to drill an exploratory well. They submitted that it was the Board's decision to approve or deny the application based on a weighing of the evidence presented before it. They suggested that the potential for denial of a well licence was one of the risks attendant with the purchase of a mineral lease.

The interveners also questioned the need for new gas reserves. At the hearing, Amoco, in response to questioning, stated that approximately 56 per cent of its gas produced in Alberta in 1993 was exported to the United States. Therefore, the interveners argued Alberta did not, per se, require more gas or gas reserves to meet its requirements, but rather that any new gas would be used to support exports.

Interveners in support of the well licence application did so based on the potential economic benefits that would accrue to the local economy and to Alberta as a whole. They believed that the potential impacts of the well could be satisfactorily mitigated and the economic benefits would outweigh any social or environmental costs.

5.3 Views of the Board

The Board accepts that Amoco, through its Petroleum and Natural Gas Lease, has the right to explore for gas in the Whaleback area, subject to it obtaining such other permits, licences, and approvals as are required by the legislation. Further, provided the public interest tests can be met, the Board accepts that an exploratory well would be needed in order to evaluate the seismic prospect, obtain geologic information, and determine the potential for future development. The Board also recognizes that there is some, albeit unknown, potential for a significant discovery in the Whaleback area and that substantial economic benefit could flow from such a discovery. The Board does note, however, that Amoco chose not to provide any technical evidence to support its predictions of either the probability of encountering hydrocarbons or the potential size of the reserves. As a result, Amoco's contention remains untested, although Amoco's estimate of the chance of a successful well appears typical of the industry. In this case, the Board concurs with the position of some of the interveners that the potential economic value of eventual development is unknown and that the value of the proposed well to the Alberta public is solely based on the information it may provide upon completion and testing.

While the Board accepts Amoco's right to explore for and develop hydrocarbons in the Whaleback and therefore its need for the well, the Board does not believe that either the acquisition of mineral rights or a surface lease agreement in any way automatically confers the right of an applicant to a well licence. The Board must balance Amoco's need for the well against the potential economic, social, and environmental costs and benefits accruing to the public from the exploration well.

Therefore, the Board would neither approve nor deny the application on the question of need alone. The Board must be convinced that certain safety, social, and environmental impacts can be or will be satisfactorily mitigated before the well would be approved. These impacts will be discussed in later sections of this report.

The Board also cannot accept the argument that because some portion of the gas found may be destined for export, that the need for the well is reduced. The Board notes that much of Alberta's economic wealth, be it from agriculture, forestry, or energy is based on the export of products. The Board believes that protecting the economic well-being of the Province is clearly one component of the public interest. The Board also notes that any attempt to limit production, if necessary to meet such an implied supply/demand test, would have to be applied fairly to the industry as a whole via the Province's gas removal policies, rather than through individual project development restrictions as proposed by some interveners. The Board does not consider such a restriction as either appropriate or necessary.

6 LOCATION OF THE EXPLORATORY WELL

6.1 Views of the Applicant

Amoco stated that it had chosen the well location based on its desire to encounter the highest crestal position on the anomaly and to locate the well on an east-west oriented seismic line. Constraining the well to a location on a seismic line was considered critical to validate its seismic interpretations. Amoco indicated that the optimal bottom-hole target area extended approximately 1 kilometre east, 0.5 kilometres west, 100 metres north, and 100 metres south of the selected surface-hole location. The selected surface location took into account environmental considerations and had been chosen after consultation between Amoco, the surface grazing lease holder, and representatives from AEP. Amoco indicated that the site it had originally selected, which was 405 metres west of the site eventually agreed upon, would have resulted in increased surface disturbance and an additional crossing of Bob Creek.

Alternative surface locations to the south had been ruled out by Amoco because a complex structural discontinuity in the anomaly was interpreted from the seismic to exist in that direction, with a corresponding drop of about 200 metres in structural elevation. Amoco contended that drilling a well in this location would also leave a substantial part of the anomaly untested. Amoco did not consider selecting a surface location further to the south and directionally drilling the well north to its preferred bottom-hole location because the well trajectory would not underlie a seismic line and so would not adequately test its seismic interpretation. Amoco said that it intended to monitor, but not specifically control, the directional drift of the well during drilling.

6.2 Views of the Interveners

Interveners opposed to the well licence application submitted that the application was deficient with respect to supporting evidence for the siting of the proposed well. In their view, because no technical evidence had been presented, it was not possible to determine if alternative locations existed. They argued that less intrusive locations, such as 2.6 kilometres further south at the end of the existing road, had not been discussed by Amoco. Amoco's contention that a structural discontinuity south of the proposed well location ruled out the possibility of moving the well south was also questioned. Again, the interveners did not believe that Amoco had provided sufficient geological or geophysical evidence to support its argument. They further questioned the likelihood that a well spudded at a surface location of 9-18 would reach a bottom-hole target in 10-18. They argued that the tendency of the well to naturally drift perpendicular to the direction of dip would, in the absence of directional drilling control, cause the well to reach total depth east of the surface location. The interveners suggested the Board defer approval of the well until geological and geophysical data supporting the location were provided.

6.3 Views of the Board

The Board recognizes that, if approved, the well must be situated so that it can reasonably achieve Amoco's objectives, while at the same time minimizing surface-related impacts. The Board accepts that Amoco would strongly prefer to locate the well on a structurally favourable position as well as along a seismic line. However, considering the potential size and trend of the structure interpreted by Amoco, the Board is concerned that alternative locations were not presented and discussed. The Board notes that the interveners expressed dissatisfaction with the lack of data presented with respect to the subsurface location of the well. This concern is shared by the Board, particularly as it relates to the technical and economic impact of moving the well to another location which would reduce surface impacts.

The reasons Amoco cited which preclude an alternative location to the south are generally understood; however, no data were presented in support of its arguments. In this regard, the Board is not convinced Amoco has adequately demonstrated the need to locate the well at the proposed location.

The Board accepts Amoco's need to retain its competitive position by not divulging information it considers proprietary, but enough information must be presented to the Board to allow the geologic limitations of alternative locations to be weighed against the potential benefits or impacts of those locations. Given the environmental sensitivity of the area, the Board questions whether the proposed 10-18 location is the only acceptable site from which to gain the geologic information of interest to Amoco. The Board recognizes that moving the well site in any direction would still result in other issues of concern to several interveners. However, the Board would prefer, in this case, to be convinced that the applied-for location is the optimum site. Prior to approving the 10-18 site, the Board would expect Amoco to address and support the rationale of site selection and possible options in more detail.

7 POTENTIAL FUTURE DEVELOPMENT

7.1 Views of the Applicant

Amoco applied for a well licence for the 10-18 well only but, at the request of the Board, identified potential full-field development options assuming the proposed exploration well is approved and ultimately is successful in discovering commercial quantities of natural gas. In an effort to minimize surface impacts which might be created by gas field development, Amoco studied three different pool development scenarios which were discussed with area residents as a component of Amoco's public consultation program. One of the following scenarios would potentially be initiated subsequent to additional successful delineation drilling north and south of the exploration well:

Scenario 1

This approach is described as a traditional program in that it involves the drilling of single wells on a total of 20 individual well pads. The access for the northwest wells will be from the west, and the remaining wells will have common road/pipeline corridors or utilize existing roads to provide access. The pipeline gathering system would probably be routed south to connect the wells in the Bob Creek valley utilizing common road/pipeline corridors. Amoco is not proposing to pursue this type of development program for any commercial development of the Whaleback area.

Scenario 2

In this scenario, Amoco proposes to utilize conventional and directional drilling to drill two wells per pad from approximately 10 pads. Similar to Scenario 1, the northwest wells may be accessed from the west, but the pipeline system will be routed to the south. The other well pads will have common road/pipeline corridors or be accessed from existing roads. Amoco stated that this is a possible development scheme, if the preferred development plan (Scenario 3) is not found to be attainable.

Scenario 3

Amoco's preferred development plan would utilize extended-reach drilling technology to permit drilling of, normally, four wells per pad from approximately 5 pads, which would significantly reduce the surface disturbance from roads, pipelines, and well sites. Similar to the other development scenarios, the northwest wells in Scenario 3 may be accessed from the west and the pipeline routed south. The other well pads will have common road/pipeline corridors or be accessed from existing roads.

Amoco also made commitments to the community that a sour gas processing plant would not be constructed in the Bob Creek valley. If gas is found in commercial volumes, Amoco proposed to transport the production by pipeline to processing facilities outside of the Bob Creek valley. Amoco indicated there are no gas plants in the region that presently have sufficient capacity to handle the anticipated Hunter Creek gas volumes. As a result, Amoco provided possible alternative concepts to process the Hunter Creek gas. These were: expansion of existing plants at either Saratoga (Crowsnest Pass Municipality) or Shell Waterton, or construction of a new gas plant in either the Crowsnest/Pincher Creek corridor or along the Highway 22 corridor.

At the hearing, Amoco noted that some of the reservoir parameters, such as depth encountered and type of fluid properties, will be factors in determining whether the preferred scenario is possible. Until the exploratory well is drilled and evaluated, any development program is speculative.

7.2 Views of the Interveners

Several interveners expressed concern with the practicality of multi-well extended-reach drilling from single pads as opposed to more traditional drilling of single wells from individual sites. As a result, they believed that if the application is approved, 20 wells on individual pads was a much more probable basis on which the development would proceed. They believed that Amoco's proposal to drill wells with between 1000 and 3000 metres of extended reach, given the probable well depth and the problems associated with encountering hydrogen sulphide, was optimistic and overly simplistic.

The interveners were particularly concerned that Amoco had not provided any technical evidence to support the capability of drilling rigs or adequacy of drill strings to drill 1000 to 3000 metre extended-reach critical sour wells to 4200 metre vertical depth. They also had a concern with Amoco's ability to maintain hole integrity and the adequacy of casing strings and well tubulars to withstand the loads and stresses to which they will be subjected under the proposed drilling scenario. Based on the above, the interveners indicated there was no evidence that supports Amoco being capable of drilling the subject well or subsequent wells directionally from multi-well pads. The interveners indicated that, in addition to their own review, the Board has also noted the difficulty of extended-reach drilling in steeply-dipping foothills geology (Decision Reports D 88-16 (Shell Whitney Creek); D 94-1 (Mobil Ricinus); and D 94-2 (Husky Moose Mountain)).

The interveners also questioned the experience of Amoco staff and the ability of the Amoco organization to safely drill a sour gas well of in the range of 4000 metres in depth. Reference was made to the Lodgepole blowout of 1982, as well as other projects where well control problems had been experienced by the oil and gas industry.

7.3 Views of the Board

The Board found Amoco's attempt to describe its potential full-field development scenario, particularly in the absence of exploratory data, useful. While the Board realizes the proposal is, at best, highly speculative, the Board believes that the exercise has provided value in assessing the costs and benefits associated with approval of the initial exploratory well. The Board is reasonably certain that, should the exploratory well be successful, Amoco will wish to develop the field in some manner. The discussion, even at this very early stage, of the range of development scenarios, allows the Board to determine if there are aspects of future development which would clearly make the proposal unacceptable. Advance notice of such a situation is presumably of benefit to all parties involved, including the applicant.

The Board notes the considerable discussion regarding the feasibility of Amoco's development scenario involving extended-reach directional drilling of up to 3000 metres of horizontal displacement. This magnitude of displacement far exceeds any other such efforts in Alberta in similar geologic settings. The Board is aware that extended-reach drilling technology has advanced rapidly in recent years with increased application of horizontal drilling, better drilling bit design, and technologies related to directional drilling with down-hole motors. The ability to achieve the displacements outlined in the development scenarios would be subject to technical constraints such as subsurface lithology and borehole stability, as well as economic constraints such as the costs related to increased use of down-hole motors. The metallurgical limitations on drill pipe and casings imposed by the high H_2S content of the reservoir and the severe weight, torque, wear, and bending stresses likely to be encountered lead the Board to question whether such drilling programs can be conducted with a suitably high degree of confidence and safety. Considering both technological advances and the lack of precedent, the Board considers Amoco's future vision to be, at best, at the outer bounds of current technology available in Alberta.

The Board believes that there is a reasonable probability that should development proceed, it is likely that more well pads than hoped for in the preferred scenario will be required, or that other changes will be needed in the development scenarios. This raises the possibility of different, and possibly more severe, environmental effects which would need to be balanced at a later stage against the claimed economic benefits from full-field development.

It is not the Board's intent to judge upon the merits of the development program at this time. The foregoing comments are offered for the purpose of providing a framework to compare the benefits of the Amoco proposal to the possible negative impacts as outlined by the Hunter Creek and Whaleback Coalitions, the Peigans, and some other interveners.

8 PUBLIC HEALTH, SAFETY, AND QUALITY OF LIFE

8.1 Views of the Applicant

Amoco, while recognizing the concerns of area residents, was confident it could drill the proposed well without seriously compromising the residents health, safety, or quality of life.

8.1.1 Drilling Activity

Amoco anticipated it would require approximately 150 to 200 days to drill and complete the proposed 10-18 exploratory well to a depth of 5600 metres with up to 1000 metres of horizontal displacement. In its submission, Amoco outlined potential incremental negative impacts which might be experienced by area residents during the drilling program and the various mitigative options it proposed to use.

The primary activities required to carry out the program included: construction of the access road; construction of the well pad; assembly, operation, and removal of the drilling rig; and completion and testing of the well. Impacts on nearby residents could include: increased dust, noise, and potential for accidents resulting from increased traffic. To reduce the impacts associated with increased traffic, Amoco proposed to restrict access to the well site to essential vehicles only, to complete construction in a timely manner, to post and enforce speed limits for its employees and contractors, to use a water well at the well site to eliminate water supply traffic, and to water the road as necessary to reduce dust. To reduce the visual and noise impacts associated with drilling and completing the well, Amoco proposed to complete these operations as expeditiously as possible.

To further reduce the impacts of its drilling program on area residents, Amoco proposed to locate its campsite outside of the emergency planning radius, in an area agreeable to the local residents, but preferably on the existing access road heading west off Highway 22 on the north side of the Oldman River. Access to the well site would be restricted by a manned gate located adjacent to the camp. Rig crews would be transferred to and from the rig in a crew vehicle in order to further reduce unnecessary vehicles travelling beyond the campsite.

8.1.2 Blowout Prevention

Amoco stated that in order to reduce the risk of loss of well control (ie. blowout), it had incorporated equipment and drilling procedures which met or exceeded the current standards and guidelines for drilling critical sour wells. Amoco had surveyed data from other wells in the vicinity to identify potential drilling problems and had incorporated solutions to these problems in its program. Amoco stated that during drilling of the well, competent supervisory staff would be on site at all times. Field information would be transmitted instantaneously to Calgary where the data could also be reviewed by Amoco's drilling personnel. In accordance with ERCB regulations, appropriate on-site personnel would be certified in well control procedures. Blowout prevention drills and safety meetings would be conducted on a regular basis.

8.1.3 Emergency Response Plan

Amoco submitted that it had prepared an emergency response plan which would ensure the safety of people in the area if a release of sour gas were to occur during drilling of the well. The plan applied to an emergency planning zone radius of 7.5 kilometres. Based on the types of drilling equipment specified, a 4 kilometre planning zone radius would normally be required. By using the larger planning area, Amoco was able to include a number of residences to the south of the drill site along the Bob Creek and Oldman River valley. The emergency planning zone included both ranchland and forest reserve and contained 9 permanent dwellings, 4 seasonal dwellings, 1 abandoned house, 1 community centre, and 1 fire lookout.

Amoco indicated that, as an additional safety measure, it would implement a voice-paging system. It proposed to use portable pagers that will be given to residents and transient land users, such as hunters and outdoor enthusiasts. The system would be used to provide a daily report on the well status, as well as to advise if an emergency situation had developed at the well. Amoco stated that this type of system had been used in the Caroline development but had not been used or tested in the Maycroft area as yet.

Amoco stated that its preferred method of dealing with public safety in the case of a blowout at the 10-18 well would be evacuation of those people at risk, rather than ignition. It also asked that the requirement for a dual (ie. redundant) ignition system be waived. Amoco submitted that it believed it had developed a plan which would adequately deal with all contingencies that might occur in the event of a blowout. As a result of its approach, Amoco concluded that if an uncontrolled flow occurred, immediate ignition of the well should not be a requirement. In response to questioning from the interveners, Amoco stated that a dual ignition system, due to the remoteness of the proposed 10-18 well, was not necessary. Amoco did agree that the well would be ignited if necessary to protect public health and safety.

8.1.4 Emissions

Amoco noted that atmospheric emissions from the well could arise from three scenarios. These were:

(a) sulphur dioxide (SO_2) associated with the flaring of controlled volumes of sour gas required as part of the testing of the completed well,

(b) hydrogen sulphide (H_2S) associated with an uncontrolled release of sour gas before ignition, and

(c) SO_2 associated with an uncontrolled release of sour gas after ignition.

Using modelled results based on an understanding of atmospheric dispersion and meteorological conditions generally associated with irregular terrain and air flows within valleys, Amoco determined the most likely concentrations of emissions in the Bob Creek valley for a range of release scenarios. Estimates of ground-level concentrations were provided along the valley floor and, in some cases, along valley ridge tops.

Ground-level SO_2 concentrations estimated to occur during flaring were based on an assumed extended test flow rate of 210 000 m^3 per day for gas containing 15 percent H_2S. Estimates of ground-level

H_2S and SO_2 concentrations from an uncontrolled gas release were based on three different gas release rates, each containing a different H_2S percentage. The uncontrolled release scenarios modelled were:

- a most-probable uncontrolled release of 570 000 m^3 per day containing 15 percent H_2S,
- a worst-case uncontrolled release from the Mississippian System of 1 605 900 m^3 per day containing 28.4 percent H_2S, and
- a worst-case uncontrolled release from the Devonian System of 3 521 000 m^3 per day containing 28.2 per cent H_2S.

The "worst-case" release values (rate and H_2S content) used corresponded to the ERCB's well licensing and emergency planning requirements. These require that the applicant combine the highest observed H_2S content from offset wells with the highest observed flow rates for the same wells. In developing both the most-probable release scenario and the worst-case scenario, the applicant used the release rates and H_2S contents of wells within the Coleman and Savanna Creek fields. An average release rate and H_2S content was used to calculate the "most-probable case".

Flaring during well testing was assumed to be from a 30-metre stack. Uncontrolled releases were assumed to be released at ground level. Ground-level concentrations were related to several atmospheric conditions and a moderate wind speed of 6 metres per second.

Estimated SO_2 Concentrations

During either flaring or ignition of an uncontrolled release of sour gas, H_2S contained in the gas is converted to SO_2. The SO_2 will initially rise due to the heat from burning, disperse, and dilute into the atmosphere and eventually return to the ground. The plume rise associated with burning the gas typically eliminates immediate danger to residents and personnel at the site.

During flaring operations, the maximum predicted ground-level concentrations of SO_2 would normally be less than 0.2 ppm as an hourly average value but, under some conditions, could reach 0.5 ppm. These values marginally exceed the provincial hourly ambient guideline for SO_2 (0.17 ppm on an hourly average basis), but peak instantaneous values could be up to three times higher. Amoco agreed that flaring during chinook winds should be avoided to prevent SO_2 impingement along the ridge tops.

In order to monitor SO_2 levels during flaring, Amoco planned to investigate the use of ambient air monitoring equipment mounted on a trailer that could be positioned by an all-terrain vehicle. Amoco stated this would significantly increase the areas in which monitoring for SO_2 emissions could take place and would enable monitoring to take place on the ridge tops adjacent to the well site.

In the event of an ignited, most-probable uncontrolled release, the maximum predicted ground-level SO_2 values would normally be less than 0.13 ppm, but could reach 0.89 ppm under some conditions. For a worst-case ignited release from the Mississippian, the maximum predicted SO_2 levels would normally be less than 0.32 ppm, but could reach 1.4 ppm. For a worst-case ignited release from the Devonian, the maximum predicted SO_2 levels would be less than 0.26 ppm , but could be as high as 1.2 ppm. The locations at which these maximums occur are dependent on wind speed and atmospheric conditions.

The highest SO_2 concentrations from ignited releases were generally associated with plumes entrained within valley air flows. During brief meteorological transition periods when air flows may expose ridge tops to the plume, concentrations of 10, 36, and 75 ppm SO_2 (on an hourly average basis) could be experienced on the ridge tops during the "most-probable", worst-case Mississippian and worst-case Devonian releases, respectively.

Estimated H_2S Concentrations

If the well were not ignited during an uncontrolled release, there would be limited lift or heat to move gaseous emissions into the atmosphere. As a result, H_2S concentrations would be highest proximal to the well and decline with distance from the well. The highest one-hour average concentrations of H_2S which were predicted to occur at the two closest residences and at the edge of the emergency planning zone are shown in Table 2. These conditions could occur at the nearest residence within 10 to 15 minutes of an uncontrolled release.

TABLE 2 GROUND-LEVEL H_2S CONCENTRATIONS (PPM) WITH DISTANCE FROM THE 10-18 WELL DURING AN UNCONTROLLED RELEASE

Release Scenarios	Distance From Well		
	2300 m (1st residence)	5900 m (2nd residence)	7500 m (edge of EPZ)
Most Probable	12	2	1
Worst Case (Mississippian)	60	12	8
Worst Case (Devonian)	140	22	18

In its submission to the Board, the Hunter Creek Coalition raised concerns with regards to the potential impacts of sour gas emissions on their health. Amoco did not, however, specifically comment on the potential risk to health associated with its predicted levels of either SO_2 or H_2S.

8.1.5 Contaminants

Amoco recognized a potential for impacts on soil, vegetation, wildlife, and water resources resulting from contaminants associated with construction activities and drilling of the proposed exploratory well and outlined its plans for waste management, spill prevention, and environmental monitoring to avoid or mitigate these impacts.

To ensure groundwater protection during drilling operations, Amoco stated it would use a freshwater-based, low-toxicity drilling fluid for the well. Monitoring of the drilling fluids for hydrogen ion concentration (pH), salinity, sodium absorption ratio, and toxicity would be performed on an ongoing basis and any necessary mitigative action would be taken to ensure compliance with existing regulations. Amoco committed to employing the latest water recycling technology to de-water the drilling cuttings and reduce the amount of waste generated.

Amoco stated its intent was to store drilling wastes prior to their disposal within the lease boundaries. Drilling waste as well as rain water and cement returns would be stored in a temporary pit prior to de-watering and the resulting solids stockpiled on the edge of the lease. Amoco intended, once it had been determined that the waste met the Board's disposal criteria, to dispose the drilling waste solids on lease and the waste liquids to the surrounding pasture lands. Amoco acknowledged that some species of wildlife are attracted to chemicals used in drilling muds and stated under questioning that, in order to avoid problems during either storage or disposal, it would install a fence around the site.

With respect to groundwater protection, it was Amoco's view that by reducing water demand through a recycling program, it could ensure minimal impact on groundwater quantity and by cementing all casing strings in the well over the full length, it could ensure no impact on groundwater quality. During questioning, Amoco admitted that it had not assessed the possibility of a hydraulic connection between a proposed water source well and Bob Creek. Amoco stated that it would commit to monitoring water quality in its water well on a regular basis, as well as to monitoring the levels of water in Bob Creek to ensure that there was no reduction in flow.

With regard to surface water contamination, Amoco acknowledged there was a concern with sedimentation and its effects on fisheries habitat. Amoco stated that during its road construction activities, all necessary precautions would be taken to prevent sediment from entering Bob Creek, including the use of a portable bridge to span Bob Creek at the single creek crossing.

8.2 Views of the Interveners

A number of area residents in support of the well noted that they believed oil and gas development could be carried out in a manner which was compatible with rural lifestyles and agricultural operations. However, the interveners opposed to the application, and particularly those living in proximity to the well, expressed significant concerns regarding the impacts from drilling even a single sour gas well within the Bob Creek valley. They noted that the area was largely unchanged since the advent of ranching in the region and supported a unique lifestyle. They were very concerned that the well represented a risk to their health, safety, and livestock. The interveners also noted that they used the area extensively for recreational purposes such as hunting, hiking, and camping. They expressed strong concerns that the qualities which made the area particularly attractive would be irrevocably lost both with the drilling of the initial well and certainly with a full-field development. The Peigan Nation expressed similar concerns regarding impacts on air and water quality, risk to Band members from an uncontrolled release and/or burning of well gases, and general disturbance from drilling activity.

8.2.1 Drilling Activity

Some concerns associated with the drilling of the well were raised. Of particular concern was the impact of increased noise, traffic, and dust from the proposed access road to the well site. Increased traffic in particular was cited as a potential safety risk as well as a source of disturbance. Concern was also raised with the presence of a relatively large work camp in a small community.

8.2.2 Blowout Prevention

The Hunter Creek Coalition expressed a number of concerns regarding Amoco's approach to optimizing the safety of its drilling program. The interveners had particular concerns with the use of grade X and used grade E drill pipe versus the use of grade SS-95, PRS-95, or new grade E drill pipe. The Hunter Creek Coalition argued the latter should be utilized in the drilling of deep critical sour gas wells, as they provide a greater margin of safety. They believed that grade X and used grade E should only be used if other grades are not available.

The interveners expressed a general concern about Amoco's quality assurance program. Such a program was critical in their view to recognize and reduce human errors and improper procedures. They noted that in the last five years the oil and gas industry has had a significant cutback in staff and particularly senior experienced staff. They believed this lack of experience was evident in the Amoco submission and that Amoco had not set forth adequate assurances that it could meet the regulations, materials, and training requirements needed to drill a critical sour well. They noted the number of errors in the original application and subsequent changes as evidence of Amoco's inability to safely drill this well.

8.2.3 Emergency Response Plan

The Hunter Creek Coalition also disagreed with the estimated flow rates used by Amoco in designing its emergency response program. They felt that rates in the range of 3 200 000 m^3/d for the Mississippian and 12 800 000 m^3/d for the Devonian systems were more appropriate, two to four times as high as those estimated by Amoco. Assuming 28.4 and 28.2 per cent H_2S respectively, the corresponding H_2S release rates would be 10.6 m^3/s and 41.8 m^3/s, and result in an emergency planning zone radius greater than the 7.5 kilometres proposed by Amoco. They noted that the enlarged emergency planning zone should also identify areas where residents live, recreationalists might be present, and provide for traffic control on Highways No. 22, 940, 517, and the nearby Chaffin Creek road.

In discussing the proposed emergency paging system, several members of both the Whaleback and Hunter Creek Coalitions expressed scepticism with its effectiveness and resentment at the inconvenience and stress of having this safety requirement imposed on their family's daily lives.

The interveners stated that they were opposed to Amoco's request for a waiver of the dual ignition system. In their view, the dual ignition system was a requirement designed to ensure public safety. They stated that redundant ignition systems ensure ignition of the well can be achieved under emergency conditions. The interveners were also concerned that Amoco's position on ignition criteria was unclear and warned of possible confusion during an emergency which may result from the differing views on the need for ignition.

8.2.4 Emissions

Members of the Hunter Creek Coalition expressed concern, given the local weather patterns, as to how either flaring operations or an uncontrolled well flow might affect air quality and their health. They noted that clean air was one of the reasons the various families have chosen to reside in the Maycroft area.

The Hunter Creek Coalition indicated that both average and poor dispersion conditions were more likely to occur in a valley than in flat terrain. They noted that poor dispersion conditions would be particularly associated with periods of down-valley drainage flows. This type of flow is likely to be established at night and to persist through the early morning hours. They also noted additional concerns about low wind speed recirculating flows that can be established within the valley and which tend to bring a plume to the ground more quickly. Recirculating flow, they noted, can be reasonably expected at the location of the well. The Hunter Creek Coalition recommended a much more detailed study of the dispersion meteorology of this area in order to establish the appropriate setback distances, as well as provide important insight into valley flows.

Of particular concern to the interveners was the potential impact of airborne emissions on their health, particularly to those two of the seven families which cited asthma problems, as well as potential risk to their livestock. A similar concern was raised with regards to other contaminants (section 8.2.5). Potential odours and other similar nuisances were also noted to be of concern, as was potential damage to vegetation from emissions. The issues raised were not specific, but rather represented a general fear of unknown impacts.

The interveners were also concerned with how impacts from emissions (or contaminants), if they did occur, could be documented. This was particularly true for their livestock, as the animals are free ranging and carcasses are often removed by scavengers before a cause of death can be determined. The interveners noted they were unsure what Amoco's policy was with respect to compensation for damage to livestock. They noted that even relatively small losses of stock would have a significant financial impact on individual ranches.

8.2.5 Contaminants

There were concerns expressed by a number of interveners regarding contaminants entering surface water and groundwater systems both from access road and bridge construction and from drilling activities.

The surface water concerns arose from a lack of information regarding specifications for road construction, specifically the kinds of cuts and fills that would be created and what stabilization measures would be employed to prevent sediment from entering Bob Creek during periods of high rainfall. The interveners felt that the lack of data impeded Amoco's ability to adequately address possible impacts on fisheries. They also felt that some level of assessment should have been done by Amoco on the potential of Bob Creek for spawning and impacts that sedimentation would have on that potential.

Groundwater contamination concerns were related to drilling the exploratory well, the water source well, and disposal of the drilling wastes at the completion of drilling. The interveners expressed concerns that Amoco had not provided significant evidence that impacts would not occur or what mitigative measures Amoco would take to ensure that contamination of groundwater resources would not occur.

8.3 Views of the Board

Given the evidence and Amoco's commitments, the Board believes the proposed well can be drilled in a safe and efficient manner and is consistent with or exceeds all current ERCB regulations. With regard to the short-term impacts of drilling activity, the Board notes that Amoco's drilling program appears to have been designed to mitigate most, if not all, of the concerns of the area residents. In general, the Board believes that the drilling program, as designed, represents a reasonable effort to reduce such impacts and is acceptable. The Board does have some concern with Amoco's estimate of the time to complete drilling, given the area's complex geology. If it was approved, Amoco would be expected to apprise both residents and the Board immediately of any significant delays in completing the well.

With regard to blowout prevention, the Board is willing to accept Amoco's contention that it fully understands the risks and requirements of drilling a critical sour well in Alberta and will ensure that the proposed drilling program is carried out in accordance with all requirements and recommended practices. While the Board shares the concerns of the interveners that there has been a loss of senior experienced personnel in the oil and gas industry, there is nothing in either the general industry safety record or in Amoco's record specifically which would suggest that the risk of loss of well control has increased as a result.

With regard to the pipe grade proposed by Amoco, the Board notes the application is consistent with current standards and the Board accepts that it is sufficient to safely drill the proposed exploratory well.

As to the emergency response plan, the Board notes that Amoco has already proposed an emergency response zone significantly larger than might otherwise be required. The Board supports this initiative since it offers a good way to communicate with residents in the area beyond the immediate area of impact and avoid unnecessary anxiety in the event of an upset in the drilling operation. Given that the emergency response zone is already calculated based on a hypothetical "worst-case scenario", the Board is not willing to require that Amoco expand its emergency response zone boundaries even further.

Regarding Amoco's request to waive the requirement for a dual ignition system, the Board believes that due to the multitude of access points into the Whaleback area and the level of use during the periods when the well would be drilled, it would be difficult to notify and instruct all transient users. The Board also has concerns with the effectiveness of Amoco's proposed pager notification system for this purpose. Therefore, the Board is not confident that evacuation is practical as the primary means of public safety and, on this basis, the Board would deny the request for a waiver of a dual ignition system for this well. The Board was also particularly concerned with the apparent lack of clarity in Amoco's proposed ignition criteria. Given the large number of transient users of the area, the Board can foresee few cases where Amoco would not carry out ignition. There should be no hesitation on a company's part to ignite an uncontrolled sour well when public safety may be compromised. The Board would expect Amoco to outline an explicit ignition criteria agreeable to the Board before drilling commences.

With regard to emissions, the Board accepts the evidence of both parties that the extreme local topography (Figure 2) and wind conditions will have a very strong bearing on dispersion. Based on probabilities, if the well were approved, the most likely scenario is that the well would be dry (62 per cent by Amoco's estimation) and emissions would not be an issue. By far, the second most likely scenario is that the well would be drilled and tested successfully, with emissions resulting from flaring but only during well clean-up and testing which are both reasonably short-term events. The evidence presented leads the Board to conclude, however, that if flaring operations were carried out without concern for specific meteorological conditions, then there is a reasonable risk that SO_2 impingement may occur. With proper care and monitoring, however, the Board does believe flaring can be carried out without risk to the health of residents, their livestock or to vegetation.

Should the well be approved and subsequently be successful, Amoco will be expected to meet AEP's Ambient Air Quality Guidelines during any flaring operations. The Board would require that in the event of an exceedance of these guidelines, Amoco would take the appropriate action, such as discontinuing flaring, reducing flaring rates, or mixing additional dilution gas into the flare stream.

The final, highly unlikely scenario, is that of an uncontrolled flow. Should loss of well control occur, Amoco has indicated it will evacuate all nearby residents immediately. Provided this action is carried out in timely and effective manner, only the residents or transients nearest to the well would be at risk and then primarily only if an unignited flow is allowed to continue for some time and no indoor shelter is available. If the well is approved, the Board will expect Amoco to satisfy it that the company has in place sufficient safeguards to adequately protect human health and safety during a blowout.

Under the blowout scenario, livestock in the immediate area would likely be at some risk, particularly if the well was not ignited. The Board does agree with the interveners that issues such as compensation for cattle loss could be dealt with prior to drilling of the well. Having such a process in place is advantageous to both parties. The Board notes the general basis for such compensation has been identified in guidelines adopted by the industry and is acceptable to the Board. The Board would expect Amoco, should the well be approved, to enter into discussions with area ranchers regarding a compensation process.

With regard to the potential impacts on surface water and groundwater systems from contaminants associated with construction and drilling operations, the Board believes that the control and monitoring measures committed to by Amoco at the hearing will adequately address those concerns.

9 PUBLIC CONSULTATION

9.1 Views of the Applicant

Amoco claimed that it had recognized at an early stage in preparing its application that the exploratory well application would generate a great deal of interest in a number of individuals and groups. It stated that as early as May of 1993, Amoco representatives were present in the Maycroft community and, in its view, information related to the proposal was readily available since that time. Amoco claimed the results of the public discussions reinforced its belief that the drilling of this exploratory well can proceed in a manner compatible with the area's present use.

The public consultation program adopted by Amoco had three distinct phases. The first phase involved initial consultation focusing on the single-well application with the primary aim to acquire the well licence, develop the emergency response plan, negotiate a suitable well site, and inform local residents, government departments and interest groups of Amoco's intentions.

Subsequent to initial contacts during the summer of 1993, Amoco assembled a community consultation team (the second phase) to explain the proposal in the area and to garner information on the residents' concerns. In addition, a public consultation expert was retained to provide assistance in reviewing Amoco's public consultation program and to augment that process. This program, which was carried out through late 1993/early 1994, culminated in at least six open house sessions intended to provide the public with general knowledge on certain aspects of the petroleum business and further information on the project. Over 150 personal discussions were also held. In addition to contacts with the community residents in the immediate vicinity of the proposed well location, presentations were made to groups in the broader Pincher Creek/Crowsnest region. First contact with the Peigan Nation occurred during the second phase in November 1993 and formal discussions with its members, including the chief, council, and elders, began the next month. Several subsequent meetings with the Peigan Nation occurred with at least one site visit conducted.

The third phase of the program involved ongoing consultation with the community, government, and interest groups in an effort to resolve issues raised during the earlier phases. Newsletters were also issued to describe the project and its status.

Amoco stated that it believed that the magnitude of its public consultation program was extraordinary for an exploratory well. In implementing its program, Amoco felt its staff demonstrated a willingness to listen to the concerns of stakeholders and to carry on a meaningful and open dialogue about the issues. In Amoco's view, reaching a resolution of any identified issue was the objective of its public consultation program. Amoco believed it had taken a leading role in the industry's relationship with the public.

Amoco claimed that during its public consultation program, it had gained considerable insight into the concerns of several groups and had altered its drilling and development programs in response to those concerns. The commitments to not build a gas processing plant in the Bob Creek valley, to provide air monitoring instruments, and to include innovative drilling techniques in possible future development scenarios were cited by Amoco as examples of accommodating resident concerns.

Amoco did, however, acknowledge that its relations with some of the residents had a "shaky start", and that some confusion and miscommunication in the early process was apparent. Since that time, Amoco believed it had implemented an extensive and sincere consultation process designed to overcome the initial difficulties. Amoco also believed it had met the expectations of IL 93-9 which states that the Board would expect, for Eastern Slopes developments, "that proponents would go well beyond the normal consultation process".

9.2 Views of the Interveners

Amoco's consultation process was given favourable comments by a number of interveners from the area. These interveners, some of whom live in the Maycroft community, stated that they generally appreciated the information Amoco supplied and the manner in which it was presented. These individuals and groups felt that a number of issues had been identified and resolved and that Amoco's plans for a community advisory committee would serve to monitor the drilling of the exploration well.

However, several interveners noted inadequacies in Amoco's attempts at public involvement. In particular, the Hunter Creek Coalition, which consists of seven local families, provided evidence which contradicted the views held by Amoco.

The members of the Hunter Creek Coalition stated that Amoco's public involvement program was flawed to the point where many of the concerns they had with the proposed development, such as human and animal health, were not dealt with effectively. These problems were the result of Amoco being unable to gain the trust of the residents, and because the consultation program adopted by Amoco did not enable local residents to be part of the decision-making process.

The Hunter Creek Coalition members stated that Amoco's initial attempts at public involvement throughout the summer of 1993 were disorganized, severely time consuming and did not establish any basis for continued dialogue. The interveners believed that they had been misled by Amoco into believing, at one point in the process, that a well licence had already been issued. In addition to feeling frustrated with the communication process adopted by Amoco, concerns were also raised about apparent contradictions in the information that was distributed and discussed by Amoco. The Hunter Creek Coalition stated that Amoco's program was completely out of step with public consultation guidelines and principles of the Canadian petroleum industry.

At the hearing, there was discussion which focused on the "no-go" option (ie. to not drill the well in the area) and how that issue was handled during the several months of public consultation. Members of the Hunter Creek Coalition felt that since the option of not proceeding with the well was never allowed on the table by Amoco, dialogue on a number of issues related to the drilling and production of the well was made more difficult and several residents did not feel that open discussions on other possibilities or locations could be realized. They also stated that the option of Amoco slowing down the well application process was never offered to the residents. As a result, many of them experienced a sense of futility in participating in the process. The position of the Hunter Creek Coalition was also supported by members of the Whaleback Coalition.

9.3 Views of the Board

The ERCB has worked with the petroleum industry and many other groups for several years in an effort to further the concepts of public involvement and communication. The Board considers this aspect of the industry as being critical to the ongoing relations with the public. As stated in IL 89-4[2], "industry and government must have the involvement and cooperation of the public in order for anything else to work". The Board is confident that the oil and gas industry, as a whole, would concur with the view that much progress has been made and much confidence has been gained with the public over the last decade.

Although IL 93-9 was not issued when Amoco submitted its application for this well, the Board believes that Amoco should have been aware of the need for particularly effective public consultation in areas such as the Whaleback. In general, Amoco's program, while it eventually was quite extensive, was primarily reactive rather than proactive, and primarily advisory rather than consultative.

The Board notes that Amoco acknowledged at the hearing that its public involvement program got off to a poor start, but believed that the initiative was now on the right track and would continue to be effective if this application were to be approved. However, the Board also notes that some of the residents who would be directly affected by the development indicated that they have lost trust with Amoco.

In the Board's view, Amoco must accept much of the responsibility for this lack of trust. It is clear that many of the area residents were left unaware of the scope of Amoco's plans for the area until the late stages of the licensing process. The first contact did not occur until after surface access had been established and after Amoco had applied for a licence from the ERCB to drill the well. Whether intentional or not, the Board also accepts that at least some of the area residents were left, after speaking with the Amoco representatives, with the impression that Amoco had also received approval from the ERCB to drill the well.

The Board believes much of the poor relations between Amoco and segments of the local community originated with Amoco's original approach to discussing its project with local residents in Phase 1 of the public consultation process. The reluctance by Amoco to consider how drilling in the area might be avoided coupled with the fixed view of some interveners that no drilling should take place led to polarized positions.

---

[2] Informational Letter IL 89-4 - Public Involvement in the Development of Energy Resources

It is evident that Amoco has now expended a significant amount of time, effort, and money to explain its project to people living in the region. Despite that effort, the Board is concerned with the lack of progress made by Amoco in re-establishing dialogue with many of the members of the community after the initial problems. The Board understands and accepts that effective public consultation in no way guarantees that the parties involved will reach consensus. Clearly, if there is no common ground between two viewpoints, then the best result one might expect from consultation is a better understanding of each other's position. In this instance, however, the Board is not convinced, based on the evidence provided, that the parties are truly committed in their efforts to re-establish dialogue. The Board believes that a renewed effort by both sides will be necessary to deal with at least some of the outstanding issues.

10 LAND USE

10.1 Views of the Applicant

In its application and at the hearing, Amoco stressed that the Whaleback Region had a long history of multiple use including ranching, hunting, recreation, and wildlife preservation, and that the proposed exploratory well was compatible with those other uses. The exploratory well and associated 2.6 km of new all-weather road would, in Amoco's view, have a negligible impact on either ranching or hunting and a minor impact on recreational and wildlife values. In particular, Amoco noted that there already existed 13.5 km of all-weather roads in the Whaleback area plus another 160 km of dirt trails, many of which were used by off-road vehicles. Amoco believed that the short length of additional road needed for the well, combined with its agreement to modify its own activities in order to reduce impacts (eg. no winter drilling, road closure, remote camp, etc.), would result in little or no disruption of the value of the area for other uses.

At the hearing, a significant amount of evidence was presented regarding whether Amoco's proposal was consistent with the Livingstone-Porcupine Hills Sub-Regional Integrated Resource Plan (IRP), a land-use management plan administered by AEP. Amoco noted that the decision of the Board, even if the Amoco proposal were at odds with the IRP, would not be bound by the land-use guidelines outlined in the IRP. This was due in part to the fact that the IRP has no force in law and in part to the intent of government that IRPs should serve only as land-use management guides. Amoco pointed to the issuance by AEP of access to the site through the MSL and LOC as further evidence that its proposal was consistent with the IRP.

Amoco noted that the IRP clearly distinguished between mineral exploration and mineral development. In its view, the applied-for well and road were clearly for exploration purposes and, given the proposed restrictions on access and timing, entirely consistent with the specific guidelines set out by the IRP for the Whaleback Ridge — Bob Creek Critical Wildlife Zone. It argued that its proposal also met the potentially more stringent wildlife protection criterion (i.e. no net wildlife habitat loss) set out by the IRP for development programs in the region.

Amoco also commented on the potential implications of Special Places 2000 to its proposal. Amoco stated that it agreed with the intent of the proposed Special Places 2000 policy in that certain areas representing each ecological zone in Alberta should be set aside for protection. Amoco noted that while it accepted that the Whaleback represented an excellent example of the montane ecosystem, five areas of montane habitat in Alberta (including the Bob Creek Ecological Reserve within the Whaleback) now had some form of environmental protection. Since protection of representative montane areas already existed in other parts of the province, Amoco believed it was appropriate and consistent with the proposed Special Places 2000 policy to consider possible oil and gas development within the Whaleback in a broader, multiple-use context, balancing its oil and gas potential against its ecological values. The mineral lease review process and the issuance of the MSL and LOC were also claimed by Amoco to be evidence that the government did not wish development in the Whaleback to halt, pending implementation of the Special Places 2000 policy.

With regard to impacts on wildlife, Amoco recognized the value of the Whaleback area to a variety of wildlife species and, in particular as a wintering area for elk. Amoco stated that the Whaleback is one of the two most important and least disturbed elk wintering ranges in Alberta and the area could be described as the most productive ungulate habitat in the entire Eastern Slopes of Alberta.

Amoco stated that it did not believe the exploratory well would impact on either elk habitat or directly on the elk population in the Bob Creek valley. Amoco concluded that since the well site is in an area of improved pasture and this type of ground cover does not constitute winter feeding habitat for elk the proposed well will not result in a net loss of habitat for wintering elk. In addition, Amoco noted that the access road alignment follows a currently rutted and compacted dirt trail that already provides negligible habitat for the elk populations that frequent the area. No disruption of wintering elk populations was anticipated because of the seasonal timing constraints imposed on the drilling activity. Amoco noted that the surface leases were issued by AEP with the condition that, for wildlife management purposes, no activity was permitted between 1 December of any given year and 30 April of the following year.

At the hearing, experts for Amoco noted that there was limited knowledge available regarding elk movements in the summer, fall, and winter. If gas reserves are found and a development scenario is proposed, additional work would be required to fully understand these movements. However, for the proposed exploratory well, Amoco stated that impacts on elk would not be an issue if seasonal constraints and access mitigation are undertaken. Amoco also committed to fencing the well site to control wildlife attraction to the area, and to monitoring elk distribution during drilling, with the objective of adjusting the schedule of operations.

Amoco argued that the IRP requirement of no net loss of habitat applied primarily to elk, with other ungulate species that frequent the area having less importance. Under questioning, Amoco admitted that this interpretation of the IRP guideline was not sanctioned by AEP, nor had this concurrence been sought.

With regard to carnivore species, expert evidence by Amoco provided the view that neither cougars nor wolves, both present in the Whaleback area, would be impacted by short-term well drilling. For grizzly bears, Amoco believed that their occurrence in the area occupied by the proposed well and access road is very likely limited to sporadic short-term visits during the early spring to early summer period. Amoco did acknowledge, however, that if there are bears using the area during the drilling period, there will likely be displacement (i.e. effective habitat loss). Amoco also admitted that it cannot demonstrate there will be no net loss of either grizzly bear or black bear habitat since the information required to reach that conclusion is not currently available. Amoco suggested that one possible mitigative method which would allow industrial development to proceed would be to reduce the amount of hunting which is allowed.

10.2 Views of the Interveners

A number of residents living in the general area expressed support for Amoco's views that oil and gas development could be carried out in a manner which would preserve other land values including ranching, hunting, recreation, and wildlife resources. Some referenced their own acceptable experience in co-existing with the energy industry.

Several interveners, most notably the Hunter Creek Coalition, the Whaleback Coalition, the Federation of Alberta Naturalists, and the Alberta Fish and Game Association as well as a number of individuals, however, disagreed strongly with the view that even the single exploratory well could be drilled without an unacceptable reduction in land-use values in the Whaleback Ridge — Bob Creek valley.

The Whaleback Coalition noted that the 1984 Eastern Slopes policy, which provides direction for the IRPs, sets out a number of goals for Eastern Slopes management. These goals included wildlife protection, recreational opportunities, management of rangelands, protection of significant ecological and archaeological values, and exploration and development of mineral resources. They noted that with the exception of mineral resource development, the area already accommodated the remaining goals. Unlike Amoco, however, the interveners did not accept that oil and gas development could be carried out in a manner which preserved other land-use values.

The interveners emphasized the lack of road development in the area. The lack of access in particular had helped in preserving the region's wilderness, recreational, and ecological values. The Hunter Creek Coalition noted how their industry, that is raising cattle, had been carried out for several decades without harming the area's other values, such as its unique ecology, and noted that they viewed their role as stewards of the lands.

With regard to the role of the IRP in Board decisions, both the Hunter Creek Coalition and the Whaleback Coalition argued that the Board must take the IRP into consideration. Furthermore, they stated that the IRP process clearly recognized that not all activities could take place in one area and that the IRP offered guidance to the Board as to how priorities should be determined in the case of conflicting uses. In this instance, they argued that the IRP clearly intended that protection of the surface values of the area was to be given precedence over development of its subsurface values. In particular, they noted that the IRP required that oil and gas development could only be carried out in a manner which resulted in no net loss of wildlife habitat, no disruption of wildlife populations, and no loss of ecological and recreational values found in the area. They noted that such a prescription was not generic to the Eastern Slopes, but rather was specific to the Bob Creek area. This, they argued, clearly demonstrated that the IRP process intended oil and gas development to proceed in some but not all areas of the Eastern Slopes. Amoco's application, they believed, could not be carried out within the confines of the IRP, particularly if the project moved beyond a single exploratory well.

The interveners noted that, although Amoco had applied only for a single exploratory well, they believed that the road to the well would greatly increase public access, and the well, if successful, would become a component of Amoco's proposed development. Therefore, it should, in their view, meet the requirements of no net wildlife habitat loss and no disruption of populations set out in the IRP for mineral development, requirements which they argued the well and access road clearly would not meet. The interveners also doubted Amoco's ability to meet the requirements set out in the IRP for even an exploratory well. For example, they questioned Amoco's ability to control access once the road had been constructed. The associated increased access would, they claimed, result in not only wildlife impacts, including increased poaching, but also in cattle rustling and random or accidental shooting of cattle.

In addition to impacts on wildlife and possibly ranching, the interveners opposed to the well all argued that industrial development in the Bob Creek valley would significantly reduce its ecological and recreational values. In particular, they noted that the exploratory well would represent the first step in a complex system of roads and well pads into an area which was fundamentally unchanged from the time of the first white settler into Alberta. For the Whaleback Coalition, this represented a complete loss of the wilderness value of Bob Creek and the Whaleback Ridge. Also at risk, they argued, was the ecological integrity of the area. The Whaleback, they stated, was made up of a complex and very site-specific assemblage of plants and animals. The loss of any species, in their view, reduced the overall ecological value of the area and could irreversibly destroy the area's unique ecology. A number of factors associated with industrial development, including direct disturbance as well as less direct impacts associated with emissions, contaminants, habitat displacement, etc., could all have an impact. The Whaleback Coalition stated that there is a real economic value in sparing the Whaleback from industrial development due to the increasing rarity of wild country and unique landscapes such as the Whaleback.

For the Peigan Nation, the well was also considered a potential risk to their traditional uses of the area.

The interveners opposed to the well also disagreed strongly with Amoco's view of the importance of the Whaleback within the Special Places 2000 program. They argued that, with the exception of a small area known as Ya-Ha-Tinda in west-central Alberta, the remaining montane ecoregions of the province had been heavily disturbed by industrial and recreational developments. The Whaleback, in their view, clearly represented the largest and least disturbed example of the montane ecosystem in Canada. As a result, they believed that the Whaleback was a prime candidate site for protection under the Special Places 2000 program. At a minimum, they argued, the Board should not make a decision which would pre-empt the potential for the Whaleback to be included within the Special Places 2000 program.

Several individual interventions offered comments on the effect the proposed well may have on wildlife. Dr. Sheppard stated that, in interpreting the no net loss principle, one needs to consider individual target species. In this case, Amoco had not provided a site-specific inventory; thus, the information required to determine the effects of the road and well site on wildlife habitat was not available. He also took exception to Amoco's conclusion that elk are the only species in this area to which the regulatory requirement of no net loss need be applied.

Mr. Lynch-Staunton, in support of Amoco's application, stated that there is a misconception that wildlife populations in the area are either fragile or in short supply. He went on to say that, as a rancher, he believed that there are too many elk and deer in the area and they have proven their ability to adapt to human activity. Mrs. Aris, citing her extensive professional contact with wellsite and pipeline areas, stated that disruption to the area is minimal, wildlife is abundant, and elk and deer use of seeded areas is extensive.

Wildlife experts for the Hunter Creek Coalition concluded that the exploratory well will indeed result in an appreciable net loss of wildlife habitat in that effective use will be altered. It was suggested that elk could be considered as a pivotal indicator species, since maintenance of a viable elk population would be indicative of the general condition of the ecosystem. Other species identified as being potentially affected by the proposal included bears, wolves, wolverines, and several birds such as eagles and woodpeckers.

The Whaleback Coalition stated that the proposed exploration well and road do not comply with the IRP guidelines for wildlife in that they will result in a direct loss of montane wildlife habitat and disrupt elk and grizzly bear populations. It was suggested that the impacts associated with the drilling of the exploratory well will extend far beyond the physical footprint of the access road and wellsite surface location.

The Peigan Nation stated that loss of wildlife habitat and emissions of H_2S and SO_2 could directly impede its ability to exercise the right to hunt and gather plants in the Whaleback area. An expert witness for the Peigan Nation suggested that, in considering the concept of no net loss of habitat, it is not a matter of an acre for acre replacement of something, but rather an evaluation of habitat functions and values. He also warned that some elk are very sensitive to disturbance, a response which depends on their past experiences, among other factors, and that the winter period would be the most critical for elk. The other species which the Peigan Nation suggested could be affected was the grizzly bear.

Some opposing interveners recommended that the application under consideration should be denied, that Amoco's investment in the mineral and surface leases should be returned, and that the leases should be recovered by the government and not be re-issued. These interveners suggested that this would constitute a "win/win" situation in that not only would the citizens of the province benefit from preservation of the unique ecological values of the area, the company would also benefit due to a significant public image boost related to its environmental consciousness, and also from probable increased sales of renewable energy devices (solar panels) manufactured by its sister company. Additionally, future generations would benefit from the retention of a "benchmark" or "reference library" montane ecosystem that would otherwise disappear. Moreover, any underlying hydrocarbon reserves would remain available to future generations if a critical need arises.

10.3 Views of the Board

The Board accepts the views presented that the Whaleback area has had a long history of multiple and highly-valued use for ranching, hunting, recreation, and wildlife. The area also appears to have significant value for native traditional uses. Although various forms of disturbance have occurred, such as seeding of pasture areas with non-native species and the development of off-road vehicle trails, the Board believes that the overall ecological integrity of the area has also generally been preserved. The question which the Board must address is whether the proposed development of the 10-18 well can be carried out in a manner which does not reduce the existing land-use values so significantly that the overall public interest is compromised.

One component of the Board's assessment of this issue has been the land-use guidelines adopted for the area in the IRP. The Board is of the view that its ultimate discretion is not fettered by the guidelines set out in the IRP and notes that the IRP clearly states that it is to be used only as a management guide. At the same time, the Board does believe that it should be cognizant of the IRP in reaching its decisions and can draw from the document valuable insights and direction into the Provincial Government's land-use goals.

The Board notes that the IRP does, as stated by the interveners opposed to the well, set out a series of priorities for resource protection in the region. Furthermore, the IRP appears to give priority to the protection of ecological and wildlife values. As argued by the Whaleback Coalition, this higher level of protection also appears to be echoed in the no net loss of habitat concept and the requirement of no loss of ecological values. The Board does not accept Amoco's argument that these tests need only be applied during the development stage. The Board believes that it would not be reasonable to prevent development activity which resulted in either habitat loss or loss of ecological values but allow exploratory activity which had the same effect.

Based on the information supplied at the hearing, the Board is not convinced, despite the efforts of Amoco to reduce drilling and construction impacts, that the requirements of the IRP, as the Board interprets that document, can be met with the applied-for well location and routing of the access road. The road extension in particular would appear, without some form of additional mitigation, to be totally inconsistent with the intent of the IRP. The Board believes that there would be at least a modest net loss of functional wildlife habitat as a result of the construction and operation of the access road and drilling site. This effect would be magnified significantly under the various development scenarios.

The Board also does not accept the narrow interpretation of no net loss of wildlife habitat offered by Amoco, although it acknowledges that no clear definition is offered in the IRP from which the guideline is taken. The Board believes that it is much more reasonable to assume that "no net habitat loss" refers to functional habitat units and would include the impacts of disturbance, harassment, and hunting. The Board also does not believe that it is reasonable to apply this principle only to elk, even given their high local importance. The Board doubts that the wildlife management intent of the IRP was single-species oriented.

It also appears that of the wildlife species utilizing Bob Creek valley, it may be elk in particular which are most sensitive due to the limited availability of over-wintering habitat, coupled with the area's high population density and the high recreational value (i.e. for hunting) of the species. At the very least, elk may provide a reasonable indication of ecosystem integrity. However, the Board also accepts the view of the Whaleback Coalition that the Whaleback region contains a unique assemblage of other plants and animals, with many of them potentially rare and/or sensitive to disturbance. The Board recognizes that it is not sufficient to consider only a single species (in this case, a large, wide-ranging mammal) and based on that determine that ecosystem integrity can be maintained.

The Board does accept Amoco's position that development of the exploratory well, provided access can be controlled, can likely be carried out with limited risk to area wildlife populations. However, the location of the well within the centre of Bob Creek valley does appear to maximize the potential risks, particularly to the elk population. This fact, when coupled with the lack of data for other species and the high value of the Bob Creek valley for elk, gives the Board concern. The Board also has ongoing concerns regarding Amoco's assertion that access, particularly during winter, can be controlled. The Board received considerable evidence at the hearing that road access represents the most significant threat to wildlife. It was also suggested that access control, once the road is in place, would be at best difficult to restrict and enforce. While the Board believes Amoco's suggestion to limit access during the drilling program would avoid negative impacts temporarily, it believes a more permanent long-term access plan needs to be developed in advance of additional proposals for the area if permanent damage to wildlife populations is to be avoided. Such plans should be supported by appropriate wildlife inventories, specific to the type of operation, designed to suit the wildlife management objectives of the area, and should have the support of wildlife officials charged with managing the area. The Board also believes some consideration should be given to restrictions to hunting or regulated controls to prevent access should energy development proceed.

With regard to the Special Places 2000 program, the Board notes the commitment by government to the initiative and expects implementation of the program will move forward in a timely fashion. The Board concurs with the views expressed that the Whaleback area is a valuable representation of an ecologically unique portion of the province. The Board accepts that it is the largest such area in the province still remaining in a relatively undisturbed condition and, as such, would likely be a prime candidate for consideration by the Special Places 2000 program. Furthermore, the Board believes that allowing oil and gas development in the Whaleback region prior to allowing the Special Places 2000 program to run its course would likely compromise its relative value to the program.

The Board is of the view that the Special Places 2000 initiative has been designed to specifically identify and evaluate unique lands such as the Whaleback within a broader provincial context. The Board believes that the Special Places 2000 process is the logical forum in which to debate the overall public value of the Whaleback from the provincial perspective. In the absence of such an evaluation having been performed at this time, the Board does not believe it would be in the public interest for it to approve an application for energy development that may, in turn, significantly compromise a scarce or unique combination of ecological values. This view is compounded by the uncertainty the Board has that Amoco has justified this proposed 10-18 location as the only one suitable for its needs at this time.

Once a decision has been made under the Special Places 2000 program for the region, the Board would be willing to reconsider an application by Amoco under the terms defined for the area. Given the reputed size of the structural anomaly, the Board certainly believes it still may be in the public interest, after the concerns raised in this decision are addressed, to evaluate at some future time the resource potential in the region. The Board would still need to be convinced that gas development could be carried out in a manner which did not unacceptably compromise the integrity of the Whaleback ecosystem or the surface values of the region.

11 DECISION RESPECTING APPLICATION NO. 931598

The Board has carefully considered all the evidence pertaining to this application. Based upon that evidence, the Board accepts that Amoco has established the need to drill an exploratory well. The Board also found that the proposed drilling and emergency response plan for the well generally meets all provincial guidelines and that the well can be drilled without undue risk to the public, although the details of the emergency response plan would have to be worked out to the Board's satisfaction with regards to notification, evacuation, and ignition. Further, the Board can accept that, from the company's position, it has attempted to select a drilling location which will optimize its probability of establishing whether hydrocarbons in commercial quantities exist within those mineral leases.

Although such an exploratory well would clearly be in Amoco's best interest, the Board must be satisfied that the proposed well would be in the overall public interest of the Province. The Board is charged under section 2.1 of the Energy Resources Conservation Act with considering "...whether the project is in the public interest, having regard to the social and economic effects of the project and the effects of the project on the environment". It is this test of public interest which must be met before a project can be deemed acceptable by the Board.

In the Board's view, the most significant issue is whether the benefit of the information which would be supplied by the exploratory well outweighs the environmental, social, and economic costs associated with such a development within the Whaleback. In carrying out this analysis, the Board took note of the planning objectives for the area set out by the Provincial Government in the IRP. From the evidence, the Board is convinced that the exploratory well is not consistent with those management goals, particularly unless access to the area can be controlled in the long term. On the basis of the evidence, the Board found it difficult to accept that Amoco can successfully develop an all-weather road into the Bob Creek valley without causing a significant long-term risk of permanently increasing public access and thereby having an unacceptable impact on wildlife and other values of the area. The Board believes a sound access control plan, consistent with the Integrated Resource Plan for the area, should be developed before any disturbance is allowed to take place.

The Board also believes that the Whaleback area represents a truly unique and valuable Alberta ecosystem with extremely high recreational, aesthetic, and wildlife values. It accepts the position of some interveners that the area is a primary candidate for protection under the provincial Special Places 2000 program. A significant component of that value lies in the relatively large and contiguous nature of the Whaleback Ridge ecosystem and the very limited disturbance which has occurred. The Board believes that for it to approve the Amoco application at this time could significantly affect the area's surface values before the Special Places 2000 program has had an opportunity to evaluate the importance of the area in a provincial context.

The Board firmly believes that the exploration for and development of Alberta's natural gas resources is a key component in the economic well-being of the Province. The Board acknowledges that the natural gas prospects in the Whaleback area may be promising and evaluation of that prospect may eventually be in the long-term public interest of Alberta. It is the Board's view, however, that the current application is deficient, that further information is required to establish if the 10-18 well site is in the most suitable location and that it should not be approved until more definitive land-use policies are prepared for the area. The Board is prepared to consider a new application upon clarification of the land-use status of the area and subject to the submission of further evidence on the issues identified in this report.

Application No. 931598 is denied.

DATED at Calgary, Alberta on 6 September 1994.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Vice Chairman

B. F. Bietz, Ph.D., P.Biol.
Board Member

R G Evans

R. G. Evans, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

APPLICATION FOR A WELL LICENCE
PORCUPINE HILLS-WHALEBACK RIDGE AREA
AMOCO CANADA PETROLEUM COMPANY LTD.

Memorandum of Decision
Pre-Hearing Meeting
Application No. 931598

---

1 INTRODUCTION

Amoco Canada Petroleum Company Ltd. (Amoco) has applied to the Energy Resources Conservation Board (the Board) for a well licence for a well proposed to be drilled on a surface location in Lsd 9-18-11-2 W5M. The well would be known as AMOCO HUNTER CREEK 10-18-11-2 and would be for the purpose of obtaining production from the Mississippian System. The well would be located in an area of south-western Alberta known as the Whaleback Ridge.

The Board was aware that a number of individuals and interest groups had concerns about the drilling of a well in this area and were requesting that a public hearing be held to address the application. To ensure all parties had an opportunity to set out their position, the Board convened a pre-hearing meeting to receive submissions respecting issues related to the application. The meeting was held at the offices of the Board on 14 December 1993. The Board members presiding at the meeting were J. P. Prince. Ph.D., R. G. Evans, P.Eng. and N. G. Berndtsson, P.Eng. The following major topics were discussed:

1. the location of the hearing,
2. the timing of the hearing,
3. the scope of the hearing, and
4. funding for local interveners.

The names of the participants who registered at the meeting are shown on the attached list.

2 VIEWS OF THE APPLICANT

Amoco stated it would defer to the wishes of the Board and local area residents respecting the location of the hearing. Amoco submitted that the hearing should commence no later than 28 February 1994.

Amoco submitted that the hearing should focus on the proposed well and not be expanded in scope to speculate on future applications since the results of the proposed well would be of paramount importance in determining what development might be proposed in the future. Amoco believed that it had already addressed a much broader scenario than normally required for an exploration well. This information, in Amoco's opinion, should be sufficient to support the application.

Respecting funding, Amoco submitted that dealing with any funding applications at a pre-hearing meeting in January, with time allotted to assess these applications prior to any hearing, would be appropriate.

3 VIEWS OF THE INTERVENERS

The interest groups and local residents represented by Mr. Harvey Locke suggested that the hearing should be held no earlier than May of 1994 in order not to interfere with local calving operations and to allow sufficient time to review the material submitted by Amoco and properly prepare for the hearing.

Mr. Locke submitted that the Maycroft Community Hall would be the most appropriate venue to hold the hearing to allow the attendance and participation of local area residents. Mr. Locke also submitted that it was their intention to file an application for funding for preparation of their submission. He also stated that his clients would want staff from Alberta Environment Protection (AEP) to be available to testify at the hearing, and, if necessary, he would wish the Board to compel their attendance.

Respecting the scope of the hearing, Mr. Locke submitted that the Whaleback Ridge area is environmentally sensitive and ecologically important, both locally and provincially. Given this, the initial question to be addressed at the hearing was whether any new development of the area should occur at all. If development is to occur then the entire potential development must be assessed, not just a single well.

Mr. McCall submitted that to allow time to prepare for the hearing, a date in May was the earliest the hearing should be convened and the venue could be Maycroft. Respecting scope, Mr. McCall stated that the entire potential development should be addressed. Further, the hearing should consider topics such as potential effects on health, traffic, and property values as well as environmental matters.

The Rocky Mountain Ecosystem Coalition (RMEC) supported a May date for the hearing. It also supported Maycroft as a hearing venue but also proposed a parallel process be held in another location, such as Calgary. RMEC also requested that the Board call for the attendance of staff from AEP to address wildlife issues at the hearing. RMEC argued that the scope of the hearing should include the full field development and also address possible cumulative effects of the proposed development.

The Federation of Alberta Naturalists (FAN) supported a May hearing date at the earliest and Maycroft for a hearing location. FAN submitted that the issue of whether development should occur at all must be addressed. If development is to proceed, the scope should include the broad development and an environmental impact assessment. FAN also supported the appearance of provincial employees at the hearing.

The Peigan Nation (the Peigans) supported the May date for the hearing. Although they did not oppose Maycroft as a hearing location, Pincher Creek would be more convenient for them. The Peigans believe the scope of the hearing should be broad in nature and shared the environmental concerns expressed by other interveners. As well, important socio-economic issues should be discussed, including impact on lands the Peigans consider to be traditional lands, sacred sites, and possibly reserve lands.

The Surface Rights Federation supported the position of addressing the development of the entire gas play and not just a single well licence application.

4 VIEWS OF THE BOARD

Considering the remarks of the applicant, the intervening parties and its own schedule, the Board believes that a hearing commencing on 25 April 1994 should allow sufficient time for the interveners to prepare. The corresponding filing date for submissions will be set for 15 April 1994. The Board notes the general support of the participants for the hearing to be held in Maycroft, and accepts that location.

Respecting requests for advance funding, the Board will entertain submissions filed no later than 24 January 1994. If a meeting is required to address these submissions it will be held at the offices of the Board on 27 January 1994, commencing at 9:00 a.m. While not limiting participation the Board expects that only counsel or other persons representing groups or individuals would need to appear at this meeting.

With respect to the scope of the hearing, some guidance is available from IL 93-9, which was issued at the close of the pre-hearing meeting. The contents of the IL had been previously discussed with the applicant, as well as with other companies active in the region.

IL 93-9 deals with potential drilling in the southern portion of the Eastern Slopes. This area has been assessed by the provincial integrated resource planning (IRP) process, which allows for public participation, and by an internal government review process under the Crown Mineral Disposition Review Committee (CMDRC). These processes, both of which include consideration of environmental sensitivities, concluded that the area should not be precluded from potential oil and gas development without site-specific assessment under the provinces' regulatory framework. It is the ERCB's legislated responsibility to provide that site-specific assessment in this case.

The Board normally attempts to determine whether new drilling is in the public interest by comparing the potential value to society of successful development with the potential costs to society imposed by that development. Those costs may include, among other things, effects on local landowners, as well as commercial, social and environmental impacts -- in general, all identifiable adverse effects attributable to the project. There are uncertainties on both sides of the equation, including, for example, the following: the presence of hydrocarbons is never certain until wells have been drilled; the social impact and the impact on the environment may depend on the scale of development and may or may not be mitigable; and the costs associated with development are sometimes difficult to quantify.

The southern portion of the Eastern Slopes is viewed by some members of the public as an important, in some areas untouched, regional ecosystem. Consequently, the Board decided to augment its normal procedures by encouraging companies to adopt a more co-ordinated approach to planning oil and gas development than has been the usual approach. IL 93-9 sets out the Board's expectations for development proposals in the area. The IL is intended to allow sufficient flexibility to accommodate the wide range of existing settings in the region, from relatively intense development to pristine, as yet untouched wildlands.

In areas with no previous energy exploration, the Board recognizes the inherent difficulty in projecting full field development at the stage of planning the first well or even initial delineating wells. The first exploratory well may be unsuccessful, thus refocusing or possibly terminating activity in that region. Or the first well may be extremely promising, suggesting that a detailed, extensive development plan is reasonable and desirable. Or it might be an unfortunate in-between situation, requiring subsequent

judgement with respect to the next well. So the Board has chosen to encourage a sequential approach to delineating and planning development, as described in the IL, that is intended to ensure the planning effort and information requirements are appropriate for the circumstances.

In the case at hand, the proposed site "is on Crown land in an area of improved pasture used by the leaseholder as a spring and fall holding area for cattle" (Application, Tab 1, page 1). At the same time, the valley where the well is proposed may be an important component of the regional ecosystem. The Board would want to be sure that the well would not alter that ecosystem adversely and irretrievably. The question bearing on the scope of the hearing is what nature and scale of information is necessary for such decisions to be reliably made.

Board staff felt, because of the area's potential sensitivity, some aspects of the decision might require more information than is usually provided in an application for a single well. Amoco's response identified three scenarios and went into some detail regarding the assumed development and environmental implications of those scenarios. The scenarios were based on a number of assumptions, some of which would be tested by the drilling of the first well. There is a considerable degree of uncertainty about the potential nature and direction of development at this time.

The application exemplifies a situation contemplated by the Board when it developed IL 93-9: one where some interveners request the broadest possible hearing to make a wide-ranging case against development, while the applicant requests a hearing limited to consideration of one well, the applied-for exploratory well, on grounds that everything else is speculative and would provide little basis for decision at a hearing. In the case at hand, the Board believes the uncertainty associated with early exploration means that attempting to define the complete development, as well as its associated environmental impact, would be, at best, speculative and inefficient and, at worst, simply not possible.

The Board believes it understands the concerns prompting some interveners to suggest this should be a hearing to determine whether any new development is acceptable. Nevertheless, the form of that question the Board must contend with at this hearing is whether or not this specific well and associated infrastructure would cause adverse effects sufficient to justify not allowing it to go ahead.

Therefore, the Board has decided that the hearing should focus largely on the applied-for well and its effects. The Board will be asking interveners to address concerns about the impacts of this well, and to assist it in determining whether or not the potential adverse effects of this well are grounds to deny it — in Mr. Locke's words, whether "the first cut" is really too deep. Some leeway will be allowed for the interveners to address broader issues within reasonable limits. However, the Board notes any future applications would be subject to the Board's scrutiny, as well as that of the interveners, and could give rise to future public proceedings. The Board sees little merit in discussing concerns related to future development that may not occur and, in any case, would be subject to the full review process.

If the first well is approved and turns out to be unsuccessful, that may end the process. Should this well be approved, drilled, and successful in locating hydrocarbons, subsequent applications would require an appropriately greater emphasis on potential environmental impacts, and detailed planning. The application review process associated with each subsequent step will provide further opportunity for interested parties to participate. The Board is confident that this procedure will effectively guard against the possibility of — again using Mr. Locke's expressive language -- "death by a thousand cuts".

Although the Board is conveying by this decision its interest in focusing on the specific application, participants should recognize that the Board does not intend to limit the scope to the very narrow issues relating only to drilling of the well. The applicant will also be asked to address possible production options. For example, if the well were approved and successfully drilled, but further drilling was later denied, the well might have to be produced on its own. With that possibility in mind, the applicant should be prepared to address the impacts of whatever facilities would be needed. The Board notes that this process puts Amoco at risk in ensuring there is sufficient information before the Board to enable it to make a decision. Amoco is also at risk to the extent that investment made in the early stages of drilling may generate a limited return if later environmental or other issues cause the Board to decide full development is not acceptable. Should this well be approved and drilled, the applicant would be well advised to plan to identify the full development requirements as early as possible.

The Board notes the requests to have representatives of Alberta Environmental Protection appear at the hearing and will advise the department of these requests. However, it is not clear to the Board that the potential contribution of those representatives to the decision the Board must make justifies requiring witnesses to appear, should they not wish to do so voluntarily.

DATED at Calgary, Alberta on 31 December 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

* R. G. Evans, P.Eng.
Board Member

* N. G. Berndtsson, P.Eng.
Board Member

* Messrs. Evans and Berndtsson were unavailable for signature of this memorandum but concur with its contents.

THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Principals and Representatives (Abbreviations Used in Report)	Representatives
Amoco Canada Petroleum Company Ltd.	F. R. Foran D. G. Amason
Federation of Alberta Naturalists	Maryhelen Posey
Hunter Creek Coalition	H. Locke
The Whaleback Coalition	H. Locke
Miler and Diane McCall	M. McCall
Rocky Mountain Ecosystem Coalition	M. Sawyer
Piegan Nation	L. Mandell
Surface Rights Federation	H. Gardener
Energy Resources Conservation Board	M. J. Bruni R. Creasey, P. Biol. N. F. Lord

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 93-9

To: All Oil and Gas Operators

13 December 1993

OIL AND GAS DEVELOPMENTS EASTERN SLOPES (SOUTHERN PORTION)

EXECUTIVE SUMMARY

This informational letter (IL) was developed by the Energy Resources Conservation Board (ERCB) to confirm to all oil and gas operators the information required for developments along the southern portions of Alberta's Eastern Slopes. These requirements have already been communicated by ERCB staff directly to some companies with active development plans in this region. This IL is intended to ensure a common understanding of ERCB requirements exists among any other potential operators in this area, as well as other potentially affected parties.

The key points of the IL are:

- Any company intending to develop a project in the region is expected to carry out a thorough and effective public consultation program consistent with the sensitivity of the area proposed for development. The program should document both issues identified and resolved.

- At each stage of development (i.e. initial pool delineation, subsequent delineation, pool development) a potential operator will provide, in as much detail as practical, its best estimate of the overall extent of development. This is required in order to avoid piecemeal proposals and to ensure that the overall scope and potential impacts of the development, if permitted, are clearly understood.

- Applicants will be required to carry out environmental assessments for each proposed development stage. These environmental assessments will be of sufficient detail to allow the Board to determine whether the project's economic benefits and mitigation programs sufficiently outweigh any remaining social and environmental costs (i.e. that the project is in the overall public interest). The level of detail expected in any environmental assessment will vary with project stage, the ultimate scope of development, the relative sensitivity of the proposed development area, and the extent of other existing and potential developments (both energy and non-energy related) in the area.

- Operators proposing developments within this region are expected to consolidate their plans and activities with other operators to the greatest degree practical wherever this may reduce area impacts.

The ERCB is of the view that this approach to the planning of new developments within the Alberta Eastern Slopes will be of benefit to operators, directly-affected parties, and to the general public. Ultimately, it is expected that this program of public consultation, project pre-planning, environmental assessment, and coordination of corporate activities will significantly help to ensure that, should developments proceed with the Eastern Slopes, they will occur in a manner which best meets the interests of all Albertans.

INTRODUCTION

The Eastern Slopes region of Alberta, particularly from Highway #1 south to the United States border (Figure 1) has the potential for significant oil and gas exploration, development, and production activity. At the outset, it must be acknowledged that the environmental sensitivities of localized areas within the region defined by Figure 1 are highly variable. As a general guideline this IL applies to undeveloped or minimally-developed areas; however, circumstances may exist such that the expectations are appropriate for certain developed areas also. Initial consultation with ERCB staff and other stakeholders would assist in determining the applicability of this IL to a given area.

The Board recognizes that this IL presents a broader regulatory approach to oil and gas development in the Eastern Slopes which is still evolving. For this reason the ERCB considers this IL as an interim document, and is prepared to revise it as circumstances warrant.

BACKGROUND

Following the posting and subsequent sale of mineral leases for several large parcels of land in the southern portion of the Eastern Slopes, various interest groups and individuals raised concerns about the possible impacts of the potential development. These mineral leases were reviewed by the Crown Mineral Disposition Review Committee (CMDRC) prior to posting and sale by the Alberta Department of Energy (AE).

The CMDRC is chaired by the Land Reclamation Division of Alberta Environmental Protection (AEP) and includes representation or available advice from all departments, agencies and boards which have a direct interest in land use, resource development and utilization, and protection of the environment and the natural resources of the province. It reviews each parcel requested for posting to determine whether surface access is possible and, if so, whether access restrictions are necessary. Surface access may be unrestricted (except for specific requirements under existing legislation), subject to additional restrictions such as increased setbacks from valley breaks, limited to specific time frames to protect wildlife, or may be prohibited. This committee follows the resource management policies and guidelines contained in the cabinet-approved Integrated Resource Plans (IRPs) and forwards its requirements to AE, also a CMDRC member, for inclusion in the postings.

The ERCB is responsible for the licensing of oil and gas wells in Alberta. As a part of that responsibility, the ERCB must ensure that exploration and development drilling, as well as subsequent production operations in a given area, are appropriate and in the public interest and that environmental impacts are acceptable.

GENERAL EXPECTATIONS

With this as background, the ERCB is aware that many forms of industrial and recreational development have already occurred throughout the Eastern Slopes region. Further, the Eastern Slopes

Policy and related IRPs provide a framework for land use planning and management. The ERCB believes that it does not have the mandate to assess the appropriateness of the Eastern Slopes Policy or IRPs, but does have the obligation to assess the impacts of a proposed energy development and the appropriateness of it for the affected area in light of that policy. The Board may conclude for instance, that while development may be permissable under an IRP, the proposed development may not be appropriate for the specific area. The ERCB therefore believes that the public interest in the Eastern Slopes region presents a need for a somewhat broader regulatory review than may be typical in more developed areas of the province.

To this end the ERCB has four main areas for which it has certain expectations, as follows:

- Public Consultation – Proponents of energy developments in this region are expected to have early and open consultation with interested parties to identify stakeholders and specific issues, baseline environmental data and further data requirements, and attempt to resolve as many issues as possible. Initial consultation with ERCB and AEP staff would assist in scoping out issues and stakeholders. Applications are to be accompanied by a full description of the consultation process, issues identified, issues resolved, and status of remaining issues including research needs.

  The consultation process should provide for a focusing of issues and resolution of as many of those issues as possible. ERCB staff are prepared to assist in the event cooperative discussions are not achieved but would expect the proponents of the development to do the necessary ground work. Because of the potential sensitivity of the area it is expected that proponents would go well beyond the normal consultation process. Whereas public hearings may be necessary, the Board believes mutual resolution of the issues outside the hearing process remains the preferred route, as it may provide for a broader scope for resolution than does the hearing process.

  A multi-stakeholder committee known as the Eastern Slopes Environment and Energy (ESEE) Committee has been established, intended to foster communication on oil and gas development issues in the Eastern Slopes. Represented on the committee are member companies of the Canadian Association of Petroleum Producers (CAPP) that have an active interest in the region, AEP, AE, ERCB staff, and several environmental interest groups. The Board supports this process and encourages on-going dialogue amongst all stakeholders.

- Development Plans – The ERCB expects applications such as well licences (initially) and other surface disturbances such as pipelines and facilities (later) to be submitted as a part of a "development plan" rather than on a piece-meal or single-well approach. Accordingly, the ERCB requires applications, including several or multi-wells as appropriate, for the following phases:

  1. Pool Delineation (initial) — The ERCB acknowledges that a definitive development plan is usually not possible at the outset. However, it is important that even with the first exploration well some outline of the conceptual developments be provided. This information, of course, cannot be very definitive but will be helpful in scoping out potential impacts and related issues. This stage of development could involve several wells, rather than separate single wells, and should address conceptual pipeline and production facility plans as well as details of measures proposed to minimize the impacts of drilling, production, and testing operations.

This phase should include baseline environmental information for the impacted area of the potential development. This information, referred to as an "environmental assessment", would be intended to assess specific sensitivities of a given area to evaluate whether or not development is indeed appropriate within that area.

2. Pool Delineation (subsequent) -- Recognizing that further delineation needs may result from initial development (should this proceed), a subsequent delineation plan may be necessary. Should this be the case, the ERCB expects composite plans rather than single-well proposals and more definite plans for mitigation of impacts from drilling, production, and testing operations (e.g. pads, innovative testing methods). Elaboration of pipeline/facility proposals would be expected also. Delineation proposals are to include well locations and associated drilling and waste management aspects, access, and test/short-term production scenarios.

3. Pool Development -- Upon delineation, a pool development plan encompassing all facilities, pipelines, and associated infrastructures would be expected. The overall objective would be to minimize the intrusion and to mitigate the impacts wherever possible.

The Board accepts that initial and subsequent delineation phases would typically provide only conceptual future plans which are subject to revision depending on drilling and testing results. Each phase is subject to a separate application and, if appropriate, public hearing process. It is therefore intended that the initial delineation phase establish whether development in the area is appropriate and, if so, what issues must be addressed in subsequent development phases. The application process for subsequent phases then provides for assurance that previously-defined issues are properly addressed, and also provides for review of new issues.

- Environmental Assessments -- The oil and gas well developments currently proposed for the Eastern Slopes region are set out in Part 2, Division 1 of the AEP Environmental Protection and Enforcement Act (EPEA) as activities for which an environmental impact assessment is not required by AEP. Notwithstanding, the ERCB will require proponents to file quality environmental data to properly assess the overall benefit/cost of these proposals. Applicants will be requested to provide to the ERCB a thorough "environmental assessment" which includes, but is not limited to, the following information:

(a) an analysis of surface site and access road selection and construction procedures;

(b) an analysis of baseline environmental conditions and major areas of concern;

(c) a description and analysis of the significance of environmental, economic, and cultural impacts including regional, temporal, and cumulative effects;

(d) options and plans to mitigate these impacts, including reasons why they should or should not be implemented;

(e) plans to monitor predicted impacts and the success of mitigation measures;

(f) emergency response plans and contingency plans to deal with unpredicted impacts;

(g) description and results of initial public consultation programs and details of any future programs proposed; and

(h) plans to minimize accidental substance release to the environment and to minimize waste.

The aforementioned represents areas that the ERCB believes necessary to assess the overall impacts of a proposed development. The ERCB believes, however, that the level of detail to which this information can or should be provided will vary depending on the phase of development being proposed. For example, requiring a full, comprehensive environmental assessment may not be reasonable or even necessary during the exploratory or "initial delineation" phases of a project.

It may still be necessary, however, to conduct sufficient environmental baseline analyses to determine what specific sensitivities exist and also to determine whether some form of development is appropriate within the project area. At the point where the potential for full-field development is more clearly defined, by comparison, comprehensive attention to the full-range of environmental assessment criteria may be warranted. It is also recognized that the environmental sensitivities of regions within the Eastern Slopes are variable, and it is reasonable to expect that the level of detail of the environmental assessment information be consistent with the sensitivity of the area proposed for development. That is to say that for areas of lower sensitivity, an overview assessment may suffice, compared to an area of high sensitivity where thorough treatment of all environmental assessment criteria would be appropriate. As a rule areas that have had little or no intrusions will be considered to be more sensitive.

In any event, the ERCB will expect the applicant to identify the sensitivity of the area and matters of potential impact early in this process and to discuss these with both government and the public to ensure the final application deals with all relevant issues, and in the appropriate level of detail to allow the Board to consider the applications.

- Consolidated Plans Amongst Operators – Operators proposing developments within the Eastern Slopes area would be expected to consolidate efforts, to whatever degree possible, involving sharing seismic or reservoir/test data, pooling efforts and resources, and use of common roads, pipeline and utility right-of-ways, and general infrastructure with efforts aimed at minimizing surface impacts and disturbances.

The ERCB's objective in documenting these expectations is to ensure sufficient information is available to make informed decisions that are in the public interest. Given the level of public interest, the Board has assigned staff to assist with and aid in coordination of the process, particularly when discussing applications under the jurisdiction of the ERCB. Notwithstanding these resources, the ERCB reiterates that it relies on the proponents of the developments to take the lead role in identifying issues, contacting interested and affected parties, and resolving issues where possible.

Questions or concerns may be addressed to Mr. Nelson Lord at 297-8159 of the Board's Drilling and Production Department, or Mr. Roger Creasey at 297-3187 of the Board's Environment Protection Department.

F. J. Mink
Vice Chairman

L. P. Prince

L. P. Prince, Ph.D.
Vice Chairman

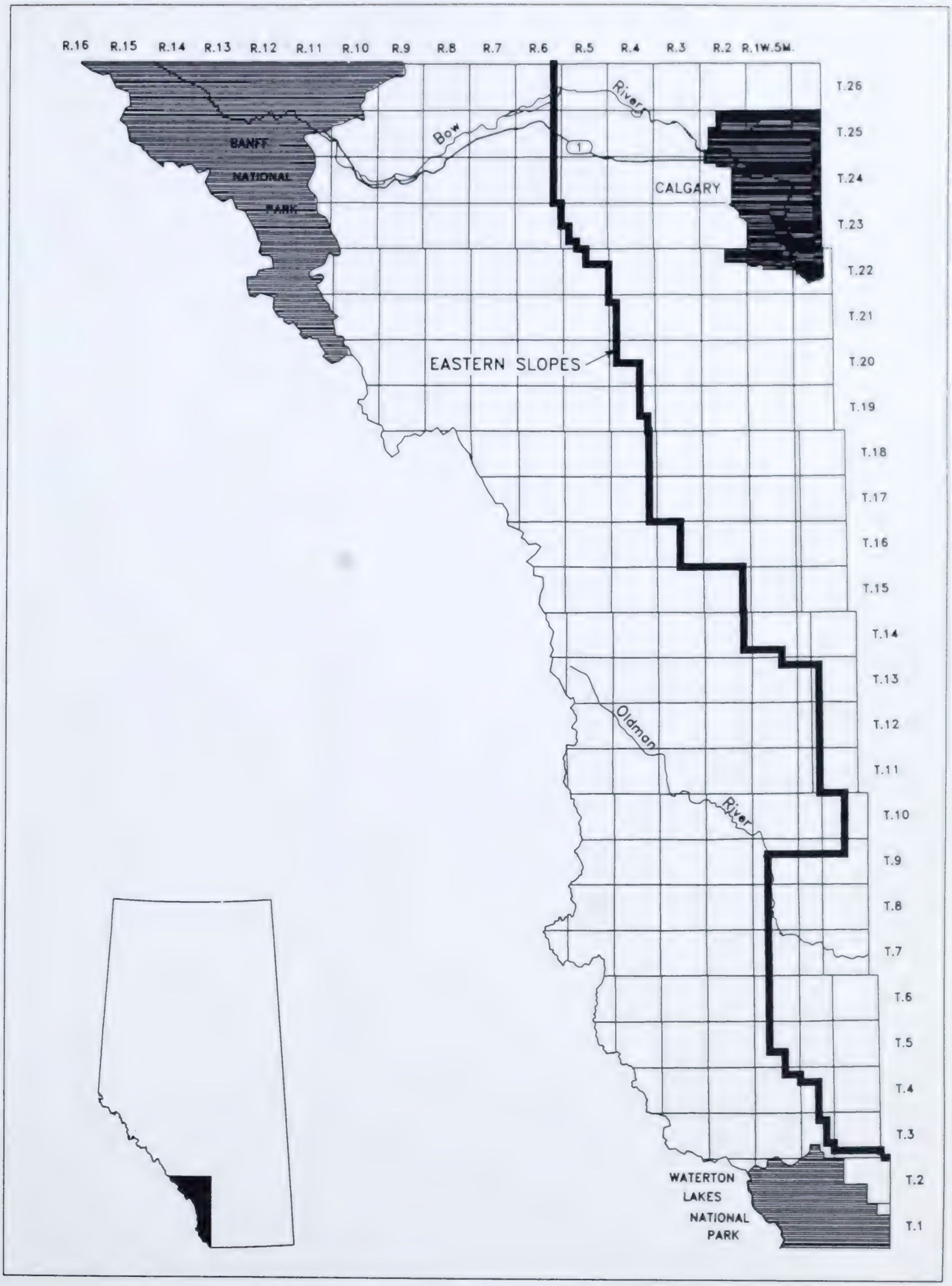


FIGURE 1 : EASTERN SLOPES SOUTHERN PORTION

DATE DUE SLIP

F255

University of Alberta Library
0 1620 0303 8021